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Economic Impact of EPA's Regulations on the Petroleum Refining Industry. Vol. 3. Pt. 3. Economic Impact Analysis

Sobotka and Co., Inc.

Prepared For
Environmental Protection Agency

April 1976

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ECONOMIC IMPACT OF EPA'S REGULATIONS ON THE PETROLEUM REFINING INDUSTRY

Part Three

Economic Impact Analysis

APRIL 1976

FINAL REPORT

Contract No. 68-01-2830

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Planning and Evaluation
Washington, D. C. 20460

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PART THREE

TABLE OF CONTENTS

Page

CHAPTER I - Summary of EPA Economic Impacts 1

A. - Price Effects of EPA's Regulations 2

B. - Impact on Sales and Output of Refineries 7

C. - Aggregate Industry Impacts 10

D. - Differential Impacts Due to Refinery Size and Configuration 16

E. - Sensitivity Analyses 22

CHAPTER II - Price Effects of EPA's Regulations 26

A. - Methodology 27

B. - Costs Incurred in Conforming the Base Version of the Model to EPA's Regulations 31

1. Water Effluent Control Costs 31

2. Airborne Effluent Control Costs 31

3. Product Quality Requirement Costs 33

4. Total EPA Costs Incurred by the Model 34

C. - Impact on Prices 35

D. - Disposition of EPA Costs 37

1. Pass-Back of EPA Costs to Suppliers 37

2. Foreign Refining Competition 39

3. Inter-Fuel Competition 40

4. Inter-Product Competition 42

TABLE OF CONTENTS (Continued)

Page

CHAPTER III - Impact of EPA's Regulations on Sales and Output of Petroleum Refineries 43

A. - Methodology 44

B. - Estimates of Price and Volume in the Absence EPA's Regulations 47

1. Consumer Prices in the Absence of EPA's Regulations 49

2. Estimates of Product Volume in the Absence of EPA's Regulations 51

C. - Volume Effects of EPA's Regulations 52

1. Gasoline 52

2. Jet Fuel (Kerosene Type) 55

3. Distillate Fuel Oil 55

4. Residual Fuel Oil 56

5. Asphalt 57

6. All Other Products 58

7. Summary of Volume Effects 59

D. - Sulfur and Lead 59

1. Sulfur 59

2. Lead 61

CHAPTER IV - Aggregate Industry Impacts 63

A. - Introduction 64

B. - Impact on Required Growth in Refinery Capacity 65

C. - Capital Needs and Annual Costs 67

1. Water Effluent Control 67

2. Airborne Emission Control 68

TABLE OF CONTENTS (Continued)

Page

C. - Capital Needs and Annual Costs (Continued)
  3. Product Quality Requirements 73
    a. Low-sulfur residual fuel oil 73
    b. Lead in gasoline 75
  4. Total Costs 78

D. Recovery and Absorption of EPA's Costs 78

E. Impact on Capital Needs for Growth 83

F. Capital Requirements of EPA's Regulations Compared to Total National Capital Availability 84

G. Employment Effects 84

CHAPTER V - Differential Impacts due to Refinery Size and Configuration 86

A. Methodolgy 87

B. Net EPA Costs for Small Refineries 88

C. Refinery Cash Flows in the Absence of EPA's Regulations 93

D. Impact of EPA's Regulations on Small Refineries 101

E. Estimated Small Refinery Closures 102

F. Employment Effects 105

CHAPTER VI - Sensitivity Analyses 106

A. Effect of Higher or Lower Capital Costs for EPA Investments 107

B. Effect of a Lower Level of Tariff Protectiion 111

C. Effect of a Lower Price Differential Between High-Sulfur and Low-Sulfur Crude Oils 114

TABLE OF CONTENTS (continued)

Page

D. Effect of Different Elasticity Estimates 118

E. Effect of Lower or Higher Crude Oil Prices 119

APPENDIX A - Refinery Expansion Requirements and the EPA Costs Thereof A-1

1. Revised Motor Gasoline Demand A-2

2. Revised Total Product Demands and New Refinery Capacity Requirements A-7

3. Downstream Processing Facilities in New Plants A-11

4. Differential Costs due to EPA's Regulations in Model Expansions A-19

APPENDIX B - Development of Net Costs for Control of Airborne Emissions A-21

1. Hydrocarbon Vapor Recovery A-23

a. Cost of Controlling Storage Tank Emissions A-23

b. Cost of Controlling Loading Rack Emissions A-31

c. Cost of Controlling API Seperator Emissions A-34

2. CO and Particulate Emission Control from Catalytic Cracking Units A-45

3. Sulfur Oxide Emission Control A-47

4. Unleaded Gasoline Including Lead Phasedown A-50

APPENDIX C - Development of Cost Data for the Small Refinery Impact Analysis A-54

1. Effluent Water Control Costs A-55

2. Airborne Emission and Product Sulfur Control Costs A-60

a. Hydrocarbon Vapor Recovery A-63

b. CO and Particulate Emissions from Catalytic Cracking A-63

TABLE OF CONTENTS (continued)

Page

2. Airborne Emission and Product Sulfur (cont'd)

c. Sulfur Regulations A-64

d. Summary A-68

3. Lead Removal Costs A-69

4. Revenue Adjustments A-74

EXHIBITS -

V-1 Net Cost of EPA's Regulations - "T"-Type Refinery 94

V-2 Net Cost of EPA's Regulations - "A"-Type Refinery 95

V-3 Net Cost of EPA's Regulations - "R"-Type Refinery 96

V-4 Net Cost of EPA's Regulations - "C"-Type Refinery 97

V-5 Small Refinery Cash Income Before Tax After Impact of EPA's Regulations - "T" and "R"-Type Refineries 103

V-6 Small Refinery Cash Income Before Tax After Impact of EPA's Regulations - "C" and "A"-Type Refineries 104

VI-1 Sensitivity Analysis - EPA Capital Costs 109

VI-2 Sensitivity to Different Capital Cost Estimates 110

VI-3 Sensitivity Analysis - Price Differential Between High-Sulfur and Low-Sulfur Crude Oils 116

VI-4 Sensitivity to Price Differential Between High-Sulfur and Low-Sulfur Crude Oils 117

VI-5 Sensitivity to Different Elasticity Estimates 120

TABLE OF CONTENTS (continued)

EXHIBITS - (cont'd)

		Page
A-1	Forecast of Additional Capacity Installation and Product Production	A-3
A-2	Products Required from Domestic Refineries in 1985	A-9
A-3	Forecast of Required Capacity Additions	A-12
A-4.A.	Processing Summary for Base Version of Model Refinery Expansion	A-14
A-4.B.	Blending Summary for Base Version	A-15
A-5.A.	Processing Summary for EPA Version of Model Refinery Expansion	A-16
A-5.B.	Blending Summary for EPA Version	A-17
B-1	Investment Cost for Storage Tank Modification	A-24
B-2	Cost of Installing Floating Roofs on Oil Storage Tanks	A-25
B-3	Number and Size of Storage Tanks to be Fitted With Floating Roofs	A-27
B-4	Cost of Storage Tank Emission Control	A-28
B-5	Cost of Modifying Crude Oil Tankage	A-30
B-6	Cost of Modifying Gasoline Tankage - "R"-Type Plants	A-32
B-7	Cost of Modifying Gasoline Tankage - "C"-Type Plants	A-33
B-8	Cost of Modifying Loading Racks - "R"-Type Plants	A-35
B-9	Cost of Modifying Loading Racks - "C"-Type Plants	A-36

TABLE OF CONTENTS (continued)

EXHIBITS - (cont'd) Page

B-10 Estimates of Hydrocarbon Vapor Loss from API Separators A-38

B-11 Annual Costs for Controlling API Separator Emissions A-40

B-12 Cost of Modifying API Separators - PAD III A-41

B-13 Cost of Modifying API Separators - PAD I, II and IV A-42

B-14 Cumulative Investment for Hydrocarbon Emission Control Measures A-43

B-15 Annual Costs for Hydrocarbon Emission Control Measures A-44

B-16 Carbon Monoxide Boiler Costs A-46

C-1 Cost of BPCTCA Treatment of Refinery Effluent Water A-57

C-2 Cost of BATEA Treatment of Refinery Effluent Water plus Effluent Reuse A-58

C-3 Cost of "Other In-Plant" Investments A-59

C-4 Water Effluent Control Costs for Small Refineries - Class A Plants ("T" and "R" Models) A-61

C-5 Water Effluent Control Costs for Small Refineries - Class B Plants ("C" Model) A-62

C-6 Cost of Airborne Emission Control in Prototype Refineries A-70

C-7 Airborne Emission Control Costs A-71

C-8 Airborne Emission Control Costs A-77

C-9 Lead Removal Costs A-73

CHAPTER I

SUMMARY OF EPA ECONOMIC IMPACTS

A. Price Effects

1. Methodology

The price analysis rests on two premises: First, the demand for petroleum products in the U.S. will increase during the 1974/1983 period so that new refinery capacity will be required. Second, total growth in U.S. petroleum product consumption will, in keeping with current U.S. policies, be furnished by U.S. refineries.

New refinery capacity will be constructed only if it is economically attractive. That is, the value added by refining must be adequate to pay operating costs and the cost of the capital required for the new capacity. Therefore, the capital required to conform with EPA's regulations in new refineries must earn an adequate return on investment. Existing plants whose EPA costs per unit of output are less than those of new refineries will receive rents. And those with higher EPA costs will absorb those that are in excess of new refineries' costs, or cease operations.

The following price analysis is used: Two "model" versions of refinery expansions will be evaluated. The "base" version is designed to manufacture products demanded in the absence of EPA's post-1973 regulations. Its waterborne and airborne emissions will reflect no post-1973 implementation of regulations. The second ("EPA") version is designed to conform to emission and product quality regulations to be implemented during 1974/1983. The cost differences between these two designs, including return on investment, are the price effects of EPA's regulations. The model chosen for this analysis is designed for a capacity of 123,000 barrels per stream day (about 100,000 barrels processed per calendar day) of 35 degree API light Arabian crude oil. Its product slate exactly meets that part of 1983 U.S. refinery outturn requirements that cannot be met by existing-in-1973 refinery capacity. The yields are:

Product	Percent Yield from Crude Oil
Gasoline	18.8
Kerosene Jet Fuel	15.0
Distillate Fuel Oil	23.3
Residual Fuel Oil	11.1
Petrochemical Feedstocks	14.3
Asphalt	5.5
Other Products	4.7
Internally Consumed	7.3
	100.0

This yield structure is quite different from that normally associated with U.S. refineries. Gasoline yield is much lower while jet fuel, distillate fuel oil and chemical feedstocks are much higher. These differences reflect the effects of the OPEC crude oil price increase and the natural gas shortage on U.S. consumption patterns. The yield structure will be achieved with crude oil distillation, vacuum distillation of atmospheric bottoms, hydrocracking (to intermediates) of vacuum gas oil and catalytic reforming of straight-run naphtha.

Product qualities differ between the two versions of the model in the following respects: 1) Motor gasoline in the base version is leaded 96 research octane number. In the EPA version it is unleaded 92 research octane number; 2) Residual fuel oil in the base version is 1.2 percent sulfur by weight. In the EPA version it is 0.5 percent sulfur; 3) Refinery fuel averages 1.6 percent sulfur in the base version, but 0.7 percent (New Source Performance Standard) in the EPA version.

2. Costs Incurred in Conforming the Base Version of the Model to EPA's Regulations

a. Water effluent control costs are about 22 cents per barrel of crude oil processed.

b. Airborne effluent control costs. In refineries of the size of the model, it is economically attractive to control all hydrocarbon emissions to the atmosphere from storage tanks, waste water treating facilities, and product loading facilities. Consequently, there are no EPA costs for controlling these emissions in the model expansion. Catalytic cracking units emit carbon monoxide and particulate matter, both of which must be controlled. Since there is no catalytic cracking unit in the model, these costs are zero. The base version of the model contains units for desulfurizing naphtha, distillate, vacuum gas oil and atmospheric bottoms. Hydrogen sulfide produced in these units will be collected and converted to sulfur in order not to exceed 1973 SO_x emission limitations. However, Claus plant tailgas cleanup will be required only under EPA's regulations. The cost for cleanup of Claus plant tailgas produced in the base version is 2 cents per barrel of crude oil processed. The EPA version of the model refinery will consume about seven thousand barrels per day of liquid fuel. The cost of desulfurizing this fuel, including the cost of recovering and converting by-product H_2S, is 7 cents per barrel of crude oil processed.

c. Product quality requirement costs. Sulfur content of residual fuel oil must be controlled to a level that will allow its consumers to meet EPA's regulations for SO_x emissions. The allocated cost, including the cost of recovering and converting by-product H_2S, is 8 cents per barrel of crude oil processed.

EPA's regulations on pollutant emissions from gasoline-powered cars and trucks are being met mostly by the installation of catalytic converters on the vehicles. Unleaded gasoline must be used by such vehicles. Other current studies indicate that the savings in lead anti-knock purchase costs will essentially offset the increased capital and associated increased processing costs required for generating higher clear pool octanes. Thus, a net zero refining cost was determined for supplying 92 octane unleaded gasoline in the EPA version of the model in lieu of 96 octane leaded product. The efficiency loss in vehicles due to lower octane is considered elsewhere in this study.

d. Total EPA costs incurred by the model are summarized below:

EPA Cost Element	Cents per Barrel Crude Oil Processed
Water effluent control	22
Airborne effluent control	
a. Claus plant tailgas cleanup of base version operations	2
b. Refinery fuel desulfurization (1.6 to 0.7 percent sulfur)	7
Product quality requirements	
a. Residual fuel oil desulfurization (1.2 to 0.5 percent sulfur)	8
b. Unleaded motor gasoline	-
TOTAL	39

3. Impact on Prices

The EPA costs summarized in the preceding section will affect petroleum product prices for the period 1974-1983. The costs of water emission control, airborne emission control and desulfurization of refinery fuel are properly allocated to all products. The cost of residual fuel oil desulfurization is necessarily allocated to all products except asphalt.1) The cost of manufacturing unleaded gasoline should be allocated to that product only. This leads to the following allocations (on the basis of heating value):

Product	Allocated Costs-Cents per Gallon
Motor Gasoline	1.0
Jet Fuel	1.0
Distillate Fuel Oil	1.1
Residual Fuel Oil	1.1
Asphalt	1.0
All Other Products	1.1

---

1) The reasoning underlying this conclusion is developed in Section C. of Chapter II.

These costs will all be passed forward to consumers as price increases. Since weighted average consumer price for petroleum products in 1983 will be on the order of 45 cents per gallon (1974 prices), the average price increase faced by consumers as a result of EPA's regulations will be about two percent.

4. Disposition of EPA Costs

a. Crude oil absorption. One might argue that a portion of the costs of EPA's regulations will be absorbed by crude oil producers in order that their markets grow as rapidly as they would in the absence of EPA costs. Two markets must be considered. First, foreign producers will be the source of the crude oil displaced by EPA's regulations. It is impractical for foreign suppliers of crude oil to discriminate between U.S. and other customers. So it would be unattractive for foreign producers to cut world prices to attempt to recoup the small volume lost in the U.S. as a result of EPA costs. Hence, no pass-back of the cost of EPA's regulations to foreign suppliers of crude oil should be expected. Second, supplies of domestic crude oil will fall well short of the intake of U.S. refineries so its price will be determined by the price of imported crude oil (or by price controls). Consequently, no significant EPA cost pass-back to domestic crude oil producers is likely.

b. Foreign refining competition. Consistent with U.S. energy policy, this entire analysis rests on the assumption of tariff (or quota) protection adequate to insure that the total growth of petroleum product consumption in the U.S. will be furnished by new U.S. refineries. Consequently, foreign refining competition has been "defined away." The extent of protection required to validate this assumption is discussed later in the report.

c. Inter-fuel competition. With the exception of transportation fuels, petroleum products compete with other energy sources in all applications. Over the period of this study it is clear that neither natural gas, nuclear energy, solar energy, hydroelectricity, nor geothermal power will be marginally available to compete with oil. Consequently, only coal (including electricity generated from coal), need be considered. Should coal competition materialize, the oil product price structure will adjust as it has in the past. That is, the price of residual fuel oil will fall below the price of crude oil, and other products will increase commensurately. (Necessarily, the weighted average price for products must be attractive if new refineries are to be built.) As a practical matter, enough residual fuel oil is imported into the U.S. that imports would be expected to bear the brunt of coal competition. The resource cost of domestic coal, including environmental costs, is equivalent to about half of the cartel price for residual fuel oil. The cartel could not compete without disrupting itself. So oil prices would be largely unchanged by coal competition, but volume would drop as coal became available.

B. Impact of EPA's Regulations on Sales and Output of Petroleum Refineries

1. Consumer prices in the absence of EPA's regulations are estimated to be as follows:

Product	Percent Of Mod Expansion Outturn	Refinery Gate Price In Base Version Of Model Expansion (Cents Per Gallon)	Consumer Price (Cents Per Gallon)
Motor Gasoline	20.3	38	63
Jet Fuel	16.2	36	39
Distillate Fuel Oil	25.1	36	44
Residual Fuel Oil	12.0	36	38
Asphalt	5.9	32	35
Other Products (all low sulfur)	20.5	36	39
	100.0		

2. Estimates of product volumes in 1985 in the absence of EPA's regulations are as follows:

Product	Forecast Domestic 1985 Consumption (Million Barrels Per Day)
Motor Gasoline	7.27
Jet Fuel (Kerosene Range)	1.52
Distillate Fuel Oil (including Kerosene)	3.79
Residual Fuel Oil	3.09
Asphalt	0.73
Other Products (all low sulfur)	1.77

3. Volume effects of EPA's regulations are estimated to be as follows:

	Effect of EPA's Regulations On Petroleum Product Consumption In the United States In 1985	
Product	Percent	Million Barrels Per Day
Gasoline	+ .7	+.051
Jet Fuel	- .3	-.004
Distillate Fuel Oil	-1.5	-.057
Residual Fuel Oil	-2.5	-.077
Asphalt	- .3	-.002
Other Products	-1.9	-.034
Total		-.123

4. Sulfur Recovery and Lead Usage Changes

Refineries will recover about 1.1 million tons of sulfur as a result of EPA's regulations. This quantity represents a small part of the United States' sulfur production which in 1971 was about 120 million tons. This, in turn, was about 43 percent of world output.

In 1973 the petroleum refining industry purchased about 959 million pounds of lead anti-knock compound valued at about 519 million dollars or 54 cents per pound. This amount of anti-knock compound contained roughly 180 thousand short tons of lead. By 1983 the purchases of lead for anti-knock compound manufacture will be reduced to about 63 thousand tons (if the lead reduction schedule is in effect) or to about 117 thousand tons (if no such schedule is in effect but new automobiles require unleaded gasoline). Annual lead production in the U.S. is roughly 600 thousand short tons and this represents only about 15 percent of world production. Thus, the reduction in the use of lead by the refining industry implies a reduction in demand of up to about a fifth of current U.S. production, or about three percent of world production.

C. Aggregate Industry Impacts

1. Capital Requirements

The gross requirements for capital to meet EPA's regulations over the period 1974 to 1983 is about 6.3 billion dollars (0.7 billion dollars per year on average). Offsetting this is a capital requirements reduction of about 0.4 billion dollars to account for new refinery capacity that would not need to be built because product demands with EPA's regulations are lower than without them. This 0.4 billion dollar reduction should not be viewed as a decrease in the impact of EPA's regulations, or as resulting in an improvement in social welfare due to a lessening in the demands for capital. The net 5.9 billion dollar capital cost of conforming to EPA's regulations represents roughly 1/6 of the replacement value of the domestic petroleum refining industry. Capital expenditures for U.S. refineries in 1973/74 averaged 1.4 billion dollars per year. Total 1974 capital expenditures for the domestic integrated oil industry (including exploration, production, refineries, transportation, distribution and marketing) were 16.6 billion dollars.

2. Impact on Growth of Refining Capacity

The combined effects of EPA regulations is to decrease new refinery capacity requirements by 33 thousand barrels per stream day. The investment cost for new refinery capacity is about 2,500 dollars per daily barrel of crude oil processing capacity. Hence, the investment requirements for new capacity will be reduced as a result of EPA's regulations by a net of 83 million dollars. This cost savings is the net of a 330 million dollar cost increase for energy manufacturing facilities needed to run EPA installations less a 413 million dollar cost decrease because fewer products will be demanded due to EPA-caused higher prices.

3. Capital Needs and Annual Costs

a. Water effluent control costs are:

	Cost - Million Dollars	
	Capital	Annual*
Existing-in-1973 Capacity		
Period 1974 thru 1977	1,610	617
Period 1978 thru 1983	553	834
New-after-1973 Capacity		
Period 1974 thru 1977	217	111
Period 1977 thru 1983	286	230
	2,666	1,064

* Operating costs plus capital charges in last year of period indicated.

b. Airborne emission control costs are:

For hydrocarbon emission control from tanks, loading racks and API separators -

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	43	6
Period 1978 thru 1983	11	7
New-after-1973 Capacity		
Period 1974 thru 1977	-	-
Period 1978 thru 1983	-	-
	54	7

For control of emissions from catalytic cracking units -

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	127	39
Period 1978 thru 1983	32	49
New-after-1973 Capacity		
Period 1974 thru 1977	6	2
Period 1978 thru 1983	-	2
	165	51

For control of sulfur oxide emissions from petroleum refineries -

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	303	100
Period 1978 thru 1983	117	144
New-after-1973 Capacity		
Period 1974 thru 1977	190	85
Period 1978 thru 1983	57	110
	667	254

c. Product quality requirements. The total costs for U.S. refineries to meet EPA's regulations for the sulfur content of residual fuel oil are:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	79	36
Period 1978 thru 1983	79	73
New-after-1973 Capacity		
Period 1974 thru 1977	175	86
Period 1978 thru 1983	52	111
	385	184

For the manufacture of unleaded gasoline, and lead phasedown -

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	1,091	107
Period 1978 thru 1983	759	303
New-after-1973 Capacity		
Period 1974 thru 1977	120	-
Period 1978 thru 1983	36	-
	2,006	303

Note: As stated elsewhere in this study, lead regulations do not impact the annual cost and price of gasoline in new capacity. But the above capital costs are real (even in new capacity) because they would not be incurred in the absence of a requirement for unleaded gasoline.

d. The total costs of EPA's petroleum refining industry regulations are:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	3,253	905
Period 1978 thru 1983	1,551	1,410
New-after-1973 Capacity		
Period 1974 thru 1977	708	284
Period 1978 thru 1983	431	453
	6,273[1]	1,863

4. Recovery and Absorption of EPA's Costs

To the extent that unit costs of conforming an existing refinery to EPA's regulations are less than the costs of conforming new refineries, the price increases that will occur will create economic rent for the plant. Conversely, if existing plant costs are greater than those for new capacity, the existing plant capital value will decline by the extent of the difference. New refinery capacity will be neither advantaged nor disadvantaged by having to conform to EPA's regulations. This is so because new refineries will only be built if the product price structure fully reflects EPA costs.

The amount of EPA costs recovered by existing refineries will equal the volume of products manufactured in these plants in 1983 times the price increase caused by EPA's regulations. With one exception, existing refineries will observe the same product price increases as were derived for expansions. The exception is residual fuel oil. The higher sulfur content residual fuel oil manufactured in 1983 in existing-in-1973 refineries will sell for fifty cents per barrel less than the low-sulfur product manufactured in expansions.

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[1] Includes 330 million dollars for facilities to provide energy to operate EPA installations.

Recovery of EPA costs is:

Recovery of EPA Costs by Existing-in-1973 Refineries

	Product Outturn In 1983 (Million Barrels)	EPA Price Increase	
		Dollars Per Barrel	Million Dollars Per Year
Gasoline	2,379	0.42	1,000
Kerosene Jet Fuel	317	0.42	133
Distillate Fuel Oil	1,012	0.46	466
Residual Fuel Oil	384	(0.04)	(15)
Asphalt	188	0.42	79
All Other Marketed Products	717	0.46	330
Total	4,997		1,993

The difference between this cost recovery and the annual EPA cost in 1983 of existing-in-1973 refineries is a (1.993 - 1.410 =) 0.6 billion dollars per year gain. That is, cash flow before tax for these plants will increase by 0.6 billion dollars per year, or about 11 cents per barrel crude oil processed. The EPA impact on existing-in-1973 refineries is a gain because the cost of conforming to EPA's regulations in these plants is, on average, less than it is in new capacity.

Capital expenditures in the U.S. during the 1974/1983 period will average roughly 150 billion dollars per year. Compared to this the net capital requirements for conforming the petroleum refining industry to EPA's regulations (0.7 billion dollars per year) is trivially small. The reader is, however, referred to a study of the construction industry[1] for a thorough discussion of the distributive effects of capital demands placed both on the capital markets and on the construction industry by EPA's regulations for all industry and Government.

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[1] Stephen Sobotka & Company, The Economic Impact on the Construction Industry of Additional Demand Caused by New Environmental Protection Standards, EPA Contract No. 68-01-0554, December 29, 1972

Implementation of EPA's regulations will increase employment in the petroleum refining industry relative to the level that would have obtained in the absence of EPA. Operators and maintenance personnel will be required for effluent treating facilities and new desulfurization and catalytic reforming units. Offsetting this will be a reduced need for employees in new plants. Employment of production and related workers in refineries in 1973 was about 89,000. Replacement value of the 1973 industry (in 1974 dollars) was roughly 39 billion dollars. Net capital requirements over the 1974/1983 period to meet EPA's regulations are six billion dollars. A first approximation, then, of the employment increase associated with the implementation of EPA's regulations on the petroleum refining industry is:

$$89 \times \frac{6}{39} = 14 \text{ thousand employees}$$

This is a highly uncertain forecast because no allowance is made for technological improvements. Nevertheless, there is no doubt that implementation of EPA's regulations in this industry will lead to employment increases over the levels that would otherwise prevail.

D. Differential Impacts Due to Refinery Size and Configuration

In Section A the impact of EPA's regulations on the cost structure of a model refinery expansion was presented. It was shown there that the annual cost increases resulting from EPA's regulations will be about 39 cents per barrel of crude oil in 1983. For capacity expansions of the type that will set industry prices in the period under study this cost increase will be exactly recovered by product price increases.

In the preceding section the impact of EPA's costs on the aggregate value of the existing-in-1973 refining industry was presented. It was concluded that, on average, the capital value of the industry was slightly enhanced by EPA's regulations.

1. Study Coverage and Methodology

89 of the smallest refineries were examined in greater detail to determine if any of these plants will be sufficiently impaired to prejudice their viability. This segment includes all but eleven of the plants with less than 20,000 barrels per day of capacity. Because it was concluded that there would be no aggregate industry capital impairment, there was no need to investigate the larger, more viable, segment of the refining industry in detail.

EPA's regulations will impact existing small refineries in two ways. The refineries will face expenditures to conform with EPA's regulations. Offsetting this, however, will be the product price increases presented in Section A above. The analysis of small refineries, then, will consist of determining the net of EPA costs and EPA-induced price increases for each small plant. The net cost (benefit) for each plant will then be compared against the cash income before tax that would be earned by the plant in the absence of EPA's regulations. If EPA net cost exceeds cash income before tax, the plant will most probably have to shut down. Conversely, if EPA cost is less than cash flows, the plant will clearly have an economic incentive to continue operation.

2. Net EPA Costs for the Small Refineries

A series of prototype model refineries was defined so that the effects of processing configuration and capacity on EPA costs could be determined. The following processing configuration classifications were considered:

"T"-type - topping plants processing low-sulfur crude oils into low-sulfur residual and distillate fuel oils, and naphtha jet fuel.

"A"-type - topping plus vacuum distillation to process high-sulfur crude oils into asphalt, high-sulfur distillates, and naphtha jet fuel.

"R"-type - topping plus catalytic reforming to process low-sulfur crude oils into gasoline and low-sulfur fuel oils.

"C"-type - topping plus catalytic reforming plus cracking (catalytic, hydro or thermal) to process low-sulfur crude oils into gasoline and low-sulfur fuel oils.

Processing capacities of 2.0, 6.0 and 18.0 thousand barrels per day were considered.

The 89 small refineries for which water effluent flow rates were available were each assigned to one of the prototype classes. There are 28 "T"-type topping plants; 20 "A"-type asphalt plants; 19 "R"-type reforming plants and 22 "C"-type plants containing cracking facilities (14 catalytic, 6 thermal cracking and/or coking, 2 hydrocracking). Product yield structure and crude type for each class were assumed to be identical to those derived for the prototypes. This assumption determined the air emission control and product quality requirements (unleaded gasoline and low-sulfur residual fuel oil) for each refinery. Size-dependent annual costs for conforming to these regulations were assigned to each refinery on the basis of the prototype studies. Water effluent control costs were assigned to each refinery based on actual 1973 water effluent flow rate and the (flow-dependent) costs of conforming the quality and quantity of this effluent to EPA's regulations.

The higher costs (relative to high-sulfur crude oils) of the low-sulfur crude oils needed by existing small U.S. refineries to meet 1973 product sulfur requirements are not costs assignable to EPA's regulations because sulfur-dependent crude oil price differentials will develop in the world market (from sulfur oxide limitations imposed by European and Japanese environmental protection authorities) independent of actions taken by the United States EPA. And world crude price differentials will determine the differentials paid by U.S. refineries.

Small refinery prototype processing configurations "T", "R", and "C" were premised to utilize low-sulfur grades of crude oil to meet 1973 product quality requirements. This is a rational premise, because the historical price differentials between high- and low-sulfur crude oils were generally too small to justify the high unit cost of installing corrosion-resistant metallurgy and product desulfurization facilities in small refineries. Also most small refineries are so located that they have good access to (formerly plentiful) U.S. low-sulfur crude oil supplies. In order to meet 1983 regulations small U.S. refineries will need to process still lower sulfur and, consequently, more costly grades of crude oil than they used in 1973. This cost differential of about 12 cents per barrel is clearly attributable to EPA's regulations.

Small "A"-type asphalt refineries are premised to process high-sulfur crude oil so they will not face relative crude price increases. However, in addition to asphalt and naphtha jet fuel, "A" plants manufacture a high-sulfur heavy distillate with physical properties intermediate between distillate and residual fuel oils. This material will not conform to EPA's sulfur content regulations. The cost estimate for desulfurizing this distillate was based on transporting it to a large refinery for processing. This costs about 21 cents per barrel crude oil processed.

Net EPA cost is the cost of conforming to water, air and product quality regulations less the increased revenue received due to product price increases caused by EPA's regulations. There is a very large variation in water effluent control costs faced by these plants - from nil to 45 cents per barrel crude oil. (The costs reflect complete conformance to BATEA requirements.) About half of the simple "T"- and "A"-type plants will be net cost-advantaged by EPA's regulations. But, because of high lead-in-gasoline control costs, all "R"- and "C"-type plants will be net disadvantaged.

3. Refinery Cash Flows in the Absence of EPA's Regulations

The revenue and cost elements needed to derive cash income before tax ("cash flow" hereafter) for a refinery include product yields, product prices, cash operating cost, and crude oil cost. Product yield structures have been premised for the base version of the model expansion and for the four prototype small refinery configurations. Prices for products will be those required to justify industry expansion.

Cash flow estimates for the small refinery prototypes are:

Estimated Cash Income Before Tax For Small Refinery Prototype
In 1983 In The Absence of EPA's Regulations
(1974 dollars per barrel crude oil processed)

	"T"	"R"	"C"	"A"
Base Expansion Cash Flow	1.84	1.84	1.84	1.84
Adjustments Relative to Base Expansion				
Product Revenue	0.22	0.43	0.66	(0.73)
Operating Cost	0.15	0.05	(0.10)	0.05
Crude Oil Cost-				
Sulfur	(0.73)	(0.73)	(0.73)	-
Metallurgy	(0.10)	(0.10)	(0.10)	-
Gravity	(0.10)	(0.10)	(0.10)	0.20
Small Refinery Cash Flow	1.28	1.39	1.47	1.36

4. Impact of EPA's Regulations on Small Refineries

No refineries will be forced to close because of EPA's regulations. This statement, of course, is an over-simplification for it ignores cases of physical infeasibility or extraordinary costs. It is possible that some of these exist. Nevertheless the protection afforded existing refineries by the inflation of refinery construction costs from 1970 to 1975 is more than sufficient to shield all but special-case refineries from serious harm by EPA's regulations.

None of the small refineries' cash income before tax is reduced by more than one-half by EPA's regulations. And the cash flow of the most affected plant is still about 70 cents per barrel of crude oil processed. If this refinery were to have an expected remaining life of 20 years, its capital value would be nearly one thousand dollars per daily barrel of stream day capacity. It is likely that the inevitable closures of certain of the older plants that are approaching the end of their normal economic life will be accelerated by EPA's regulations. Similarly the closure of plants whose viability is adversely affected by changes in crude oil supplies or customer requirements may also be accelerated.

5. Employment Effects

The 100 small refineries in the continental U.S. of 20 thousand barrels per day capacity or less have an aggregate capacity of approximately 800 thousand barrels per day and employ about 7,000 persons. Since no plants are expected to close solely because of the impact of EPA's regulations, the employment effect of these regulations is to increase employment by a small amount.

E. Sensitivity Analyses

1. Effect of Higher (and Lower) Capital Costs for EPA Investments

Total annual EPA-caused costs rise from 1.9 billion to 2.3 billion dollars in the 25 percent higher-, and drop to 1.4 billion in the 25 percent lower capital cost cases. Higher unit capital costs for conforming new refinery capacity to EPA regulations will cause higher per-barrel annual compliance costs, and (identically) higher EPA-caused price increases. So less new refinery capacity will be needed. For existing-in-1973 refineries the cost to conform to EPA's regulations will increase, but so will cost recovery.

There will be negligible change in the numbers of small refineries advantaged/disadvantaged by EPA's regulations. In other words, varying EPA capital estimates plus or minus 25 percent has no significant effect on the viability of the small refineries studied.

2. Effect of a Lower Level of Tariff Protection

The major effect of a lower level of tariff protection would be that no new refinery capacity would be constructed that is not now firmly planned. Therefore, the price increases necessary to justify EPA costs in such plants would not be forthcoming.

A tariff level 40 cents per barrel below the level needed to encourage expansion of EPA- forming refinery capacity was assumed. This level of tariff would eliminate new refinery construction and lead to substantially lower cash income before tax for existing refineries.

At the lower level of tariff EPA's regulations would have no effect on prices in the U.S. market. This is because prices would be set by imported products not subject to EPA's regulations. So there would be no recovery of EPA costs. And there would be no volume effects of EPA's regulations.

At the base tariff level, EPA's regulations lead to an increase in cash flow to existing-in-1973 refineries of about eleven cents per barrel. At the lower tariff level the entire EPA cost of 28 cents per barrel would have to be absorbed. This is a substantial impairment of cash income but it is not so large as to force abandonment of any known plants, including small ones.

3. Effect of a Lower Price Differential Between High-Sulfur and Low-Sulfur Crude Oils

The cost of EPA's sulfur regulations are strongly influenced by the sulfur content price differential. The basic analysis used an implied differential of 86 cents per barrel per percent sulfur. A zero differential was chosen for the sensitivity analysis. Intermediate values can be adequately estimated by linear interpolation.

It was found that existing-in-1973 refineries are relatively advantaged by EPA's sulfur regulations. This is because percent yield of residual fuel oil and use of liquid refinery fuel are lower in these plants than in refinery capacity expansions. The competitive impact of EPA's regulations on small refiners is essentially independent of the sulfur price differential and hence of sulfur regulations.

4. Effect of Different Demand Elasticity Estimates

Per barrel costs of EPA's regulations are independent of elasticity. So EPA-caused price changes are also independent of elasticity estimates. Consequently, capital costs, annual costs, and cost recovery for existing-in-1973 refineries, and impacts on small refineries, are unaffected by changes in demand elasticity estimates.

Different elasticity estimates do have effects on the total EPA costs of new refinery capacity. Relative to the base analysis the effects of a more elastic demand response are to decrease product consumption, investment requirement for growth, and investment required to meet EPA's regulations. The effects of a less elastic demand response are similar, but in the opposite direction; i.e., increased product consumption and investments.

5. Effect of Lower or Higher Crude Oil Prices

A three dollar per barrel reduction of crude oil price (from 12.75 dollars per barrel delivered to U.S. refineries to 9.75 dollars) would decrease the costs of EPA's regulations in the model expansion by about two cents per barrel crude oil processed (due to the lower value of refinery fuel). This results in trivially lower product prices. EPA costs to existing-in-1973 refineries would be slightly increased because some investments would become EPA-caused rather than profitable. Competitive impacts on existing-in-1973 small refineries would be about the same as at the base crude oil price.

Because price affects quantity demanded, a crude oil price of 9.75 dollars per barrel would require about twice the volume of new refinery capacity to be constructed during 1974/1983 as was needed at a 12.75 dollar price. So EPA-caused costs for new capacity would be twice those shown in the base case.

The effect of a one dollar per barrel crude oil price increase (to 13.75 dollars) would be consistent with the price decrease results, but in the opposite direction. That is, the EPA impact on existing-in-1973 refineries would be almost the same as at 12.75 dollars per barrel, but capital requirements for expansion capacity would be less.

A crude oil price increase of five dollars per barrel (to 17.75 dollars) would have a profound impact on the petroleum refining industry. Product consumption in 1983 would be decreased so that there would be some retirements of existing-in-1973 facilities. In that event prices would reflect the cash-out-of-pocket costs of the least efficient refiner who was needed to balance the market - all higher cost plants would close. In such an economic climate the only EPA cost recovery that could occur would come from the cash operating cost increase experienced by the least efficient refiner who was able to stay in business. Essentially the entire capital costs of EPA's investments would have to be absorbed by the industry.

A 15.75 dollars per barrel price (three-dollar increase) could produce intermediate effects. The effect would be to require additional refining capacity to manufacture distillate fuel oil, jet fuel and petrochemical feedstocks, coupled with a reduction in the output of gasoline and residual fuel oil in existing refineries. At a crude oil price of 12.75 dollars per barrel, the EPA cost of manufacturing unleaded gasoline in new refineries is nil. Consequently, at that crude oil price, existing-in-1973 refineries are forced to fully absorb the cost of converting to unleaded gasoline. So a higher crude oil price will not further disadvantage existing plants on this account. The cost of controlling sulfur content of residual fuel oil and refinery liquid fuel would be only slightly increased by crude oil prices higher than 12.75 dollars per barrel crude oil. Net, the impact of EPA's regulations on existing-in-1973 refineries would be about the same at crude oil prices of 15.75 and 12.75 dollars per barrel.

CHAPTER II

PRICE EFFECTS OF EPA'S REGULATIONS

A. Methodology

The price analysis rests on two bases. First, Government and industry forecasts show that the demand schedule for petroleum products in the U.S. will increase during the 1974/1983 period covered by this study. This means that new refinery capacity will be required to be built. Second, it is assumed that adequate tariff protection will be provided such that the total growth in petroleum product consumption will be supplied by U.S. refineries. There is currently in effect a tariff ("license fee") of 21 cents per barrel of crude oil and 63 cents per barrel of petroleum products. The differential protection of 42 cents per barrel (1 cent per gallon) may not be adequate to protect the domestic refining industry from new refineries constructed in crude oil exporting countries. This subject will be developed more fully in Section D.2. of this chapter.

New refinery capacity will be constructed only if it is economically attractive. That is, the value added by refining (price-times-volume of products less price-times-volume of crude oil) must be adequate to pay operating costs and the cost of the capital required for the expansion. This means that the capital required to conform new capacity to EPA's regulations must also earn an adequate return on investment. A corollary of this argument is that existing plants whose EPA costs per unit of output are less than those of new capacity will receive rents. And existing plants with higher EPA costs will have to absorb those that are in excess of new capacity costs, or in extreme cases, cease operations.

The methodology for the price analysis is now clear. A "model" U.S. refinery expansion will be defined. Two versions of this model will be evaluated. The first ("base") version will be designed to manufacture products that would be demanded in the absence of EPA's post-1973 regulations. Also refinery waterborne and airborne emissions will reflect no post-1973 implementation of regulations. The second ("EPA") version will be designed to conform to emission and product quality regulations to be implemented during 1974/1983. The cost differences between these two designs, including return on investment, are the price effects of EPA's regulations in a growing petroleum refining industry.

The model chosen for this analysis is a "block expansion" of an existing refinery. A block expansion is less expensive than a new "grass roots" refinery because many auxiliary facilities need not be supplied in total, e.g., roads, office buildings, laboratory, maintenance shops, loading facilities, etc. Such existing services can usually be extended at modest cost. Also, block expansions are more likely to take place than grass roots because environmentalist opposition to expansions is markedly less vigorous than against new plants. There are currently four large refinery construction projects underway in the U.S.1) Only one of these (ECOL in Louisiana) is grass roots; the other three are block expansions.

The model expansion is designed for a capacity of 123,000 barrels per stream day of 35° API light Arabian crude oil.2) This quality of crude oil is expected to be in ample supply throughout the period under study and is a reasonable example of crude oils expected to be imported into the U.S.

The capacity of the model is somewhat less than most major expansions now underway. Hence, because of scale economies in refinery construction, it may be slightly more expensive. However, because no grass roots expansions were assumed, it appeared reasonable to study a block expansion of slightly higher unit expense than an optimum one.

The model expansion is designed to yield a product slate that will exactly meet that part of 1983 product volume requirements from U.S. refineries that cannot be met by existing-in-1973

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1) Part Two, Table A-4.

2) Assuming 90 percent on-stream factor and 90 percent effective utilization of calendar day capacity, crude processed throughout the year will average

$$123{,}000 \times 0.9 \times 0.9 \approx 100{,}000 \text{ barrels per calendar day}$$

refinery capacity (operating at 81 percent of stream day capacity). The derivation of these yields is detailed in Section 2. of Appendix A. The yields required from refinery capacity expansions are:

Product	Percent Yield from Crude Oil
Gasoline	18.8
Kerosene Jet Fuel	15.0
Distillate Fuel Oil	23.3
Residual Fuel Oil	11.1
Petrochemical Feedstocks	14.3
Asphalt	5.5
Other Products	4.7
Internally Consumed	7.3
	100.0

This yield structure is quite different from that normally associated with U.S. refineries. Gasoline yield is much lower than typical and intermediates (jet fuel and distillate fuel oil) are much higher than typical. These differences reflect the effects of the OPEC crude oil price increase on U.S. consumption patterns. The yield structure is achieved with crude oil distillation, catalytic reforming of straight run naphtha, vacuum distillation of atmospheric bottoms and hydrocracking (to intermediates) of some of the vacuum gas oil. The model refinery configuration is developed in Appendix A, Section 3.

Product qualities differ between the two versions of the model in the following respects:

1. Motor gasoline in the base version is leaded 96 research octane number (weighted average of 94 octane and 100 octane grades). In the EPA version, motor gasoline is unleaded 92 research octane number.

2. Residual fuel oil in the base version is 1.2 percent sulfur by weight. This is the average sulfur

level supplied to the U.S. market in 1973.1) In the EPA version, residual fuel oil is 0.5 percent sulfur, which is the average level required for consumption growth 1974-1983.2)

3. Refinery fuel (liquid and gas) averages 1.6 percent sulfur in the base version. This sulfur level is equivalent to the 1973 average for residual fuel oil consumed in U.S. P.A.D. Districts II and III.3) In the EPA version sulfur content is 0.7 percent as required by the Federal standard for large new stationary sources.

Distillate fuel oil sulfur content is assumed to be the same in both versions. This is because competition in the U.S. market has typically required that distillate fuel oil sulfur content not exceed 0.25 percent. This sulfur level also meets EPA's regulations. Desulfurization of middle distillates is required when Arabian crudes are processed.

Both the base version and the EPA version are equipped with crude oil distillation, vacuum distillation, naphtha desulfurization, naphtha reforming, distillate desulfurization, vacuum gas oil hydrocracking, vacuum gas oil desulfurization and atmospheric bottoms desulfurization. Both versions are equipped with floating roof tanks on crude oil and gasoline storage tanks, and hydrocarbon vapor recovery from loading racks and API separator, because such facilities are financially attractive. Both versions contain hydrogen sulfide recovery (amine) and conversion (Claus) facilities. Waste water flow in the base version is 33 gallons per barrel. The EPA version is further equipped with additional amine and Claus capacity, a Claus plant tailgas cleanup unit, a higher severity catalytic reforming unit, vacuum bottoms desulfurization, and a full complement of water treating and recycling facilities to enable conformance with BATEA requirements.

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1) Part Two, Table V-5.

2) Ibid, page V-14.

3) Ibid, Table V-5.

The balance of this Chapter will be devoted to deriving the cost differences between the two versions of the model, the price effects that will result from these costs, and an analysis which shows that essentially all these costs will be passed forward to petroleum product consumers. The analysis will be restricted to costs that will be recognized in 1983. It is not possible to compute price effects before the Energy Policy and Control Act of 1975 expires in mid-1979. Until that time petroleum product prices will be controlled. One can only guess whether control regulations will or will not permit the costs of conforming to EPA's regulations to be passed through as product price increases.

B. Costs Incurred in Conforming the Base Version of the Model to EPA's Regulations

1. Water Effluent Control Costs

Page III-18 of Part Two indicates that 265 million dollars per year will be spent by expansion refineries in 1983 to achieve BATEA guidelines. Page III-16 indicates 4,131 thousand barrels per stream day of new crude capacity is covered by this category. This represents a cost of about 22[1] cents per barrel[2] of crude oil processed.

2. Airborne Effluent Control Costs

There are four classes of this cost category.

a. Hydrocarbons can be emitted to the atmosphere by evaporation from storage tanks, from waste water treating facilities, and from product loading facilities. It is shown in Appendix B that it is economically attractive to control all these sources in refineries of the size of the model. Consequently, there are no costs for controlling hydrocarbon emissions in the model expansion.

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[1] Assuming 90 percent on-stream factor and 90 percent effective utilization of calendar day capacity.

$$\frac{265 \times 10^6}{4{,}131 \times 10^3 \times 365 \times .9 \times .9} = .217 \text{ dollars per barrel}$$

[2] One barrel is 42 U.S. gallons.

b. Catalytic cracking units emit carbon monoxide and particulate matter, both of which must be controlled. Since there is no catalytic cracking unit in the model these costs are zero.

c. The base version of the model contains units for desulfurizing naphtha, distillate, vacuum gas oil and atmospheric bottoms, Hydrogen sulfide produced in these units will be collected and converted to sulfur in order not to exceed 1973 SO_2 emission limitations.1) However, Claus plant effluent gas cleanup will be required only under EPA's regulations.

In practice, all the sulfur recovery activities in the refinery, including those associated with the operations described in the following two sections, will be combined in a single facility for minimum cost. Consequently, the cost required for this activity of 2 cents per barrel of crude oil processed is an allocated fraction of the total sulfur recovery costs developed in Appendix A, Section 4.

d. The EPA version of the model refinery will consume about eight thousand barrels per day of fuel. (Refinery fuel is measured in liquid fuel equivalent barrels; one barrel is 6.3×10^6 BTU.) As described above, sulfur content must be reduced from 1.6 percent in the base version of the model to 0.7 percent in the EPA version. Refinery liquid fuel will be desulfurized in the same vacuum bottoms desulfurizing unit that is used to desulfurize residual fuel oil product. The allocated fraction of the cost of running this unit, plus the cost of recovering and converting by-product H_2S, is 7 cents per barrel of crude oil processed. The costs and allocations are developed in Appendix A, Section 4.

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1) These operations are essentially breakeven in any case: Part Two, Tables IV-14 and IV-15.

3. Product Quality Requirement Costs

a. As discussed above the sulfur content of residual fuel oil must be controlled to a level that will allow consumers to meet EPA's regulations for SO_x emissions. The Table on page V-14 of Part Two shows that an average residual fuel oil sulfur content of about 0.5 percent will be required for product manufactured in new facilities during the time period under study. Residual fuel oil will be desulfurized in the same processing units used to desulfurize refinery liquid fuel. The allocated fraction of the cost of running these units, plus the cost of recovering and converting by-product H_2S, is 8 cents per barrel of crude oil processed. The costs and allocations are developed in Appendix A, Section 4.

> NOTE: Asphalt does not require desulfurization. So, sale of this high sulfur material (about 4.5 percent sulfur) significantly reduces the cost of meeting EPA's regulations in the model expansion.

b. EPA's regulations on pollutant emissions from cars and trucks are being met mostly by the installation of catalytic converters on the vehicles. These converters require that unleaded gasoline be used for reasonable catalyst life. It is assumed that all of the gasoline manufactured in the EPA version of the model expansion will be unleaded material of about 92 research octane number. In the base version of the model, 96 research octane number gasoline is made with a lead content of 2 grams per gallon. 96 is about the optimum octane number for overall least cost per mile to gasoline consumers (assuming that cars are designed to utilize it).

The refining costs for supplying 92 octane unleaded gasoline in refinery expansions versus an equal volume of 96 octane leaded product were not explicitly developed by the technical subcontractor in Part Two. That analysis was focused on the costs incurred in modifying existing plants (with accompanying small crude capacity increases). It is more expensive to retrofit octane generating facilities in an existing plant than to incorporate them in the construction of an expansion.

Other current studies[1)] indicate that in new refineries the savings in antiknock cost (about 0.5 cents per gallon at a dosage of two grams of lead per gallon) will essentially offset the higher capital and operating costs required for generating higher clear pool octanes. So the refining cost for supplying 92 octane unleaded gasoline in lieu of 96 octane leaded product is (net) zero.

4. Total EPA Costs Incurred by the Model

The cost estimates derived above are restated in the following table.

EPA Cost Element	Cents per Barrel Crude Oil Processed
Water effluent control	22
Airborne effluent control	
a. Claus plant tailgas cleanup of base version operations	2
b. Refinery fuel desulfurization (1.6 to 0.7 percent sulfur)	7
Product quality requirements	
a. Residual fuel oil desulfurization (1.2 to 0.5 percent sulfur)	8
b. Unleaded motor gasoline	-
TOTAL	39

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1) The Pace Company, Economics of Producing Unleaded Gasoline in New Refineries, August, 1974.

C. Impact on Prices

The cost elements derived in the preceding section constitute factors that will affect prices for the period 1974-1983 as a result of EPA's regulations. The costs do not impact all products equally. The costs of water emission control, airborne emission control and desulfurization of refinery fuel are properly allocated to all products. The cost of residual fuel oil desulfurization is necessarily allocated to all products except asphalt. The cost of manufacturing unleaded gasoline should be allocated to that product only. (Since the net cost is zero, this allocation is irrelevant.)

The allocation of EPA costs to product classes is not arbitrary but derives from the following reasoning:

Waterborne emission control, airborne emission control and refinery fuel desulfurization are fundamental to the basic business of refining. Thus, the costs of these processes are properly allocated to all finished products equally. Conversely, when EPA costs are undertaken on behalf of a single product, it alone should bear the cost. Thus, the cost of conforming gasoline quality to EPA's regulations should be borne solely by gasoline. (In practice, this particular cost is nil. But the concept is correct.)

Clearly, none of the cost of desulfurizing residual fuel oil to meet EPA's regulations should be allocated to asphalt, for asphalt is essentially undesulfurized residual. But it is not possible to assign all of the desulfurizing cost to residual fuel oil for two reasons. First, the asphalt and high sulfur coke markets are quite limited so most residual petroleum must be sold as residual fuel oil.1) Second, no one is willing to pay a higher price for low sulfur residual fuel oil than for low sulfur distillate fuel oil2). There is only one way to reconcile these two constraints: The cost of residual fuel oil

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1) Or uneconomically hydrocracked to light products at roughly fifty percent higher cost than desulfurizing.

2) These products have essentially equal heating values. Also see Section D.4. following.

desulfurization must be borne equally by all products (except asphalt) as is waste water treatment.

The principle of equal allocation of costs to all low sulfur products is clear. But the application is necessarily arbitrary, for there are several reasonable bases on which to allocate, e.g., per gallon, per unit market value, per pound, etc. Of these, allocation on the basis of heating value (BTU) seems most appropriate, for most refinery products are fuels.

Of course, there are minor differences in sulfur content, and there are form-value premiums among the various low sulfur fuel products. Nevertheless, the EPA costs can reasonably be allocated at the refinery gate on the basis of heating value. This leads to the following allocations:

EPA Costs in Refinery Expansions

Product	Allocated Costs-Cents Per Gallon
Motor Gasoline	1.0[1]
Jet Fuel	1.0
Distillate Fuel Oil	1.1
Residual Fuel Oil	1.1
Asphalt	1.0
All Other Products	1.1

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1) Computation for gasoline:
0.92 volume recovery of all liquid products
0.865 volume recovery of all liquid products minus asphalt
31 cents per barrel crude processed for conforming waterborne, airborne and refinery fuel emissions.
8 cents per barrel crude processed for desulfurizing residual fuel oil.
5.25 million BTU per barrel heating value for gasoline
5.60 million BTU per barrel weighted average heating value for all products

$$\frac{31}{.920 \times 42} + \frac{8}{.865 \times 42} \quad X \quad \frac{5.25}{5.6} = 0.96 \text{ cents per gallon}$$

It will be shown in the next section of this chapter that these costs will all be passed forward to the consumer as price increases. Since weighted average consumer price for petroleum products in 1983 will be on the order of 45 cents per gallon (1974 prices), the average price increase faced by consumers as a result of EPA's regulations will be about two percent. The effects of such price increases will be developed in Chapter III.

D. Disposition of EPA Costs

A fundamental premise in this analysis is that refinery expansion will take place in the U.S. only if full costs, including EPA costs, can be recovered and an adequate rate of return earned. Given this premise the costs calculated above must be recovered by the petroleum refining industry. There are two issues to be considered to determine how these costs will be recovered. The first is whether the costs will be passed back to crude oil suppliers or passed forward to product consumers (or some of both). The second issue is that prices of individual petroleum products may vary within the overall constraint that weighted average prices must go up by about one cent per gallon over the levels that would exist in the absence of EPA's regulations. These subjects will be discussed below.

1. Pass-Back of EPA Costs to Suppliers

One might argue that a portion of the costs of EPA's regulations will be absorbed by crude oil producers in order that their markets grow as rapidly as they would in the absence of EPA costs. Two markets must be considered. First, foreign producers will be the source of most or all of the crude oil needed by new capacity during the period 1974/1983. It is impractical for these suppliers to discriminate between U.S. and other customers because the ultimate destinations of crude oil shipments are very difficult to control. Other export markets for foreign crude are an order of magnitude larger than the export market to the U.S. These two considerations would make it very unattractive for foreign producers to cut prices to attempt to recoup the volume lost in the U.S. as a result of EPA costs. In view of this, no pass back of the cost of EPA's regulations to foreign suppliers of crude oil should be expected.

The second source of crude oil is from domestic producers. Because supplies of domestic crude oil will fall well short of the intake of U.S. refineries, the price of this oil will be determined by the price of imported material rather than by resource cost or domestic competition (except if price controls or import limitations provide otherwise). If the price of imported crude oils is not affected by EPA's regulations, then neither will be the price of domestic crude oil (though it may differ as a result of an import tariff).

Some crude oils are produced and refined in comparatively isolated areas of the U.S. If a refinery in such an area were to close, then the local crude oil would drop in value because it would have to be shipped to a more distant point for refining. In such cases a small downward revision in the price of crude oil supplied to the threatened refinery might take place. This type of situation does not occur frequently enough to affect the average level of crude oil prices. Since the refineries which will be able to pass back crude oil prices are likely to be small (or else they would not serve isolated markets), the fraction of industry output that might be involved in pass back will necessarily be trivial.

Because of sulfur emission regulations throughout the world the price of high sulfur crude oil is declining relative to the price of low sulfur material. The eventual equilibrium market price differential will reflect fuel oil and refinery fuel desulfurization costs in large plants. But the per-barrel cost of desulfurization is higher in small refineries than it is in large plants. So suppliers of high sulfur U.S. crude oil to small refineries may have to absorb this cost difference to keep the refineries from switching to low sulfur crude oil.

2. Foreign Refining Competition

It will be recalled that this entire analysis rests on the assumption of tariff protection adequate to insure that the total growth of petroleum product consumption in the U.S. will be furnished by new U.S. refineries. Consequently, foreign refining competition has been "defined away".

Currently there is a tariff (fee) structure which provides about a one cent per gallon level of protection to domestic refineries. (The effective tariff is normally higher for new facilities.) This level of protection may be inadequate to protect domestic refineries from potential competition by new refineries built in OPEC countries. This is because OPEC members realize very large rents on each barrel of crude oil or product that they export, so the incentive to export more at the expense of other cartel members is high. For example, gross crude oil producing costs in the Persian Gulf (P.G.) area are less than one half dollar per barrel. The total unit cost of owning and operating a new refinery in the P.G. would not exceed three dollars per barrel[1]. Consequently, the total refinery gate cost of refined product would be less than 3.5 dollars per barrel. Crude oil in the P.G. sells for about 10.5 dollars per barrel. So, the sale of incremental refined products even at prices nearly identical to that of crude oil would net 7.0 dollars per barrel.

From the foregoing, it appears that building export refineries is an attractive way for a cartel member to "cheat" (increase his sales at the expense of other cartel members) without endangering the cartel crude oil price. This logic implies that a protective tariff of about three dollars per barrel might be necessary to guard new domestic refineries against aggressive OPEC member

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1) Turner, Mason & Solomon, private correspondence, July 18, 1975.

actions[1]. Of course, import quotas could be imposed to achieve the same purpose. But quotas are subject to erosion by political pressure, both domestic and foreign.

In the absence of cartel pricing, domestic refineries would need protection against foreign refineries to the extent that true economic costs differ. On the one hand, refinery construction costs in remote areas are higher than they are in the U.S. Also total labor costs for operating refineries are probably lower in the U.S. because U.S. operators and mechanics are much more productive. Further, it is cheaper to ship crude oil to refineries than products to scattered terminals, even though the quantities of products are less (due to refining fuel consumption). On the other hand, fuel costs in export refineries will always be less than in U.S. plants, either because the fuel is locally produced natural gas with low alternative use value or because it is valued at crude oil price excluding transportation to the U.S. And, of course, foreign environmental protection costs are lower.

It is beyond the scope of this project to quantify all of the foregoing cost differences. However, the differences due to EPA's regulations between a U.S. refinery expansion and an offshore exporting refinery expansion are about 40 cents per barrel. This is made up of 22 cents for water effluent control, 2 cents for Claus plant effluent cleanup, and something more than twice 7 cents for refinery liquid fuel desulfurization[2]. (Offshore exporting refining expansions would face just about the same costs as U.S. refining expansions for residual fuel oil desulfurization and unleaded gasoline manufacture.)

3. Inter-Fuel Competition

With the exception of transportation fuels, petroleum products compete with other energy sources in all applications.

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1) The price margin between crude oil and products required to justify new EPA-conforming domestic refineries is about three dollars per barrel.

2) Seven cents is the cost to desulfurize from 1.6 to 0.7 percent sulfur. But offshore export refineries can utilize fuel with sulfur contents well above 1.6 percent.

Over the period of this study it is clear that neither natural gas, nuclear energy, solar energy, hydroelectricity, nor geothermal power will be marginally available to compete with oil. Consequently only one competing fuel, coal (including electricity generated from coal), need be considered. It is possible that enough coal will be available by the mid-1980's to limit the price of residual fuel oil in large industrial and utility applications. Until recently, natural gas and imported residual so limited the price of domestic residual. Should coal competition materialize, the oil product price structure will adjust as it has in the past. That is, the price of residual fuel oil will fall below the price of crude oil, and other products will increase commensurately. Necessarily, the weighted average price of all products in aggregate must be attractive if new refineries are to be built.

As a practical matter, enough residual fuel oil is imported into the U.S. that imports would be expected to bear the brunt of coal competition. It will be recalled that existing law permits a tariff of up to 63 cents per barrel to be placed on imported residual, although historical practice has been to waive or greatly reduce the tariff. Should domestic coal competition become significant, one would expect the Federal government to focus this competition on imported residual. This can be done by reducing or eliminating the waivers from tariff that are now granted.

In the long run, the resource cost of domestic coal, including environmental costs, will be equivalent to about six dollars per barrel (1975 price) of residual fuel oil1). Domestic crude oil production would increase only slowly at such a price2), and the cartel could not compete without disrupting itself. So oil prices would be largely unchanged, but volume would drop as coal became available.

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1) Sobotka & Company, Inc. "Impact of Increased Coal Use on the Clean Fuels Deficit", EPA Contract #68-01-2407 Task Order #6, February 14, 1975.

2) Federal Energy Agency, Project Independence Report, November 1974, page 81.

4. Inter-Product Competition

It was concluded above that competition among refinery fuel products will lead to EPA costs being under-recovered by residual fuel oil and over-recovered on other low sulfur products. This is because residual fuel oil could not be sold if it were priced at the cost of crude oil plus residual fuel oil desulfurization. In Appendix A it is shown that vacuum bottoms desulfurization is required in the EPA version of the model expansion to meet residual fuel oil sulfur content requirements. The cost of this operation is about nine cents per gallon of vacuum bottoms, or about two cents per gallon of blended residual fuel oil product. If this cost were to be allocated totally to residual fuel oil, the resultant price would substantially exceed the price of distillate fuel oil. However, the latter has a higher form value and lower sulfur content than residual fuel oil. The only reconciliation of this problem is to conceptualize residual fuel oil desulfurization as a process required by the entire refinery, rather than just by residual fuel oil. The effect of this reasoning is to reduce EPA cost recovery by residual fuel by about 1-3/4 cents per gallon and increase EPA cost recovery by all other products (except asphalt) by 1/4 cents per gallon.1)

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1) $$2 \text{ cents} \times \frac{0.11 \text{ residual fuel oil yield}}{0.865 \text{ all product yield (except asphalt)}} = 0.25$$

CHAPTER III

IMPACT OF EPA'S REGULATIONS ON SALES AND OUTPUT OF PETROLEUM REFINERIES

A. Methodology

In the preceding chapter the impacts of EPA's regulations on prices of petroleum products were developed. In this chapter the effect of these price changes on petroleum product consumption will be derived. Because this analysis is based on an assumption of tariff protection for domestic refineries, effects on consumption are identical to effects on refining industry output.

The volume effects of EPA's regulations will be computed from the equation for the demand curve:

$$Q_2 = Q_1 \left(\frac{P_2}{P_1}\right)^e, \text{ or } \quad \frac{Q_2 - Q_1}{Q_1} = \left(\frac{P_2}{P_1}\right)^e - 1$$

Where, P_1 is consumer price of a product in the absence of EPA's regulations,

P_2 is P_1 plus the impact of EPA's regulations on the price of the product as derived in Chapter II,

Q_1 is the volume of the product that would be consumed at price P_1

e is the price elasticity of demand[1], and

Q_2, the unknown, is the volume consumed at price P_2.

The values of P_1 are the sum of raw material price plus manufacturing costs (for the base version of the model expansion defined in Chapter II) plus distribution and marketing costs. That is, they are the long run consumer prices that would exist in the absence of EPA's regulations. Estimates of these data can be derived from construction cost and historical information.

Adequate estimates of Q_1 are available from several National Petroleum Council studies. However, it was necessary to modify their gasoline forecast. Elasticity estimates are available in Project Independence Report and from other sources.

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[1] Note that demand elasticities are negative numbers so that higher prices lead to lower volumes.

A note of caution regarding the level of accuracy of the estimates to be presented is in order. Both Q_1 and EPA's costs (P_2 minus P_1) can be estimated with fair accuracy. But the P_1 and elasticity estimates are uncertain. As regards P_1, the absolute levels of petroleum product prices are predominantly dependent on the effectiveness of OPEC and on U.S. government policies. OPEC increased the delivered world price of crude oil from about \$3 to about \$12 per barrel between 1973 and 1975. Within the U.S., average delivered crude oil prices rose from about \$4 to a current average of about \$8.

Clearly, OPEC and the U.S. government exert profound influence on the levels of petroleum product prices to be used in this analysis. The average impact on product prices of EPA's regulations is about 40 cents per barrel. However, a price increase of this size will have only slightly greater effects if refinery average gate prices are \$6 per barrel than if they are \$14 per barrel1). That is, volume effects are insensitive to price level.

Very little is known about the long run elasticity of demand for petroleum products in the U.S. at forecast price levels. The available elasticity estimates are based on observations during times when refinery gate prices averaged roughly \$4 per barrel. It is doubtful that elasticity is unaffected by the absolute level of price. Unfortunately, it will be some years before enough data is available to permit confident elasticity estimates.

The use of a single estimate for the price elasticity of demand applicable to all possible prices of a product is

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1) Assume e = -1.0. Then, $\frac{Q_2}{Q_1} = \frac{P_1}{P_2}$. For P_1 = \$14. $\frac{Q_2}{Q_1} = \frac{P_1}{P_2} = \frac{14}{14.4} = \underline{\underline{0.9722}}$. For P_1 = \$6, $\frac{Q_2}{Q_1} = \frac{6}{6.4} = \underline{\underline{0.9375}}$. $\frac{0.9722}{0.9375} = 1.04$, thus, a 4 percent greater volume effect at \$6 than at \$14. If e = -0.5, the relative effect is 2 percent.

equivalent to saying that users' percentage response to a given percentage price change is independent of the price level. When product prices change a great deal this assumption may not be useful. On the other hand, there is a common view that people's ability to adjust consumption patterns decreases as price increases, that is, that easy-to-shed consumption is displaced first as prices rise and that successive price increases bring on progressively smaller adjustments. This view is consistent with an assumption of constant (or increasing) elasticity:

Assume $Q_1 = 100$, $P_1 = 100$, $P_2 = 110$ and $e = -1.0$.
Then $Q_2 = (100)\left(\frac{100}{110}\right)^{1.0} = 90.9$ and $Q_1 - Q_2 = \underline{\underline{9.1}}$

If $Q_1 = 50$, $P_1 = 200$ and $P_2 = 220$,
Then $Q_2 = 50\left(\frac{200}{220}\right)^{1.0} = 45.45$ and $Q_1 - Q_2 = \underline{\underline{4.55}}$

So the consumer's "ability to adjust" need be only half as great at high price/low volume as at low/high for the assumption of constant elasticity to hold.

As a practical matter elasticity estimates have been published recently by several investigators. Project Independence Report, for example, includes a significant analysis of some price elasticities. However, these derivations, no matter how soundly based theoretically, have not yet been tested in the U.S. market at current price levels.

The above notes of caution are not meant to cast doubt. Rather they are intended to alert the reader to the magnitude of the inherent uncertainties of the analysis.

The balance of this chapter will be devoted to deriving the volume effects on each principal petroleum product of EPA's regulations. The following section will be devoted to developing the base for the analysis, that is, estimates of P_1 and Q_1. In Section C, elasticity estimates will be developed and the quantity effects computed.

B. Estimates of Price and Volume in the Absence of EPA's Regulations

The object of this analysis is to derive the quantity of volume changes associated with EPA's regulations. Derivation of price (P_1) and quantity (Q_1) in the absence of EPA's regulations is, therefore, a means to an end. Quantity change, ($Q_2 - Q_1$), is quite insensitive to estimates of P_1 1). Consequently it was not necessary to perform detailed engineering cost estimates for the base model expansion. Nor was it necessary, with one exception, to derive new volume forecasts. Quantity change is sensitive to EPA costs ($P_2 - P_1$) and to elasticity. Because these points are so important, they will be elaborated arithmetically.

Later in this chapter the following estimates will be developed for gasoline:

P_1 = 63 cents per gallon

Q_1 = 7.27 million barrels per day and

$e = -0.76$

In Chapter II, $P_2 - P_1$ was shown to be about 1 cent per gallon. The estimate of P_1 was derived from three elements: crude oil cost (30 cents per gallon), refining cost (8 cents) and marketing distribution cost including consumer taxes (25 cents).

1. Sensitivity to refining cost.

a) Assume refining cost is 8 cents per gallon

$$Q_2 - Q_1 = Q_1 \left[\left(\frac{P_1}{P_2}\right)^e - 1 \right] = 7.27 \left[\left(\frac{63}{63 + 1}\right)^{0.76} -1 \right]$$

$Q_2 - Q_1 = -0.087$ million barrels per day

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1) See Footnote 1, page 45.

b) Assume refining cost is 6 cents per gallon

$$Q_2 - Q_1 = 7.27 \left[\left(\frac{63 - 2}{64 - 2}\right)^{0.76} - 1 \right] =$$

-0.090 million barrels per day

c) Hence, a 33 percent change in base refining cost leads to a 1- $\frac{90}{87}$ = -0.034, or a 3 percent change in the estimated volume impact.

2. Sensitivity to base volume (Q_1).

   As the above equation shows, $Q_2 - Q_1$ is proportional to Q_1. Hence, a 30 percent change in Q_1 would lead to a 30 percent change in the estimated volume impact.

3. Sensitivity to EPA cost.
   If EPA costs were 2 cents per gallon instead of 1 cent

   $$Q_2 - Q_1 = 7.27 \left[\left(\frac{63}{63 + 2}\right)^{0.76} - 1 \right] =$$

   -0.171 million barrels per day

   Comparing to 1.a) above,

   $1 - \frac{0.171}{0.087} = -0.97$. Hence a 100 percent change in EPA costs leads to a 97 percent change in the estimated volume impact.

4. Sensitivity to elasticity.
   If demand elasticity were -1.0 instead of -0.76,

   $$Q_2 - Q_1 = 7.27 \left[\left(\frac{63}{64}\right)^{1.0} - 1 \right]$$

   = -0.114 million barrels per day
   Comparing to 1.a) above,

   $1 - \frac{0.114}{0.087} = -0.31$. Hence, a 32 percent change in elasticity estimate leads to a 31 percent change in the estimated volume impact.

The foregoing exercises show that estimates of the volume impact of EPA's regulations are most sensitive to base volume, EPA costs and elasticity. They are quite insensitive to base refining cost estimates The base volume estimates to be used herein are unlikely to differ as much as 10 percent from the true value (if such could be derived). However, since elasticity and EPA costs are so important, the effect of different values of these parameters will be investigated in Chapter VI.

1. Consumer Prices in the Absence of EPA's Regulations

The consumer price of a petroleum product can be disaggregated into three useful segments - crude oil price, refining cost, and marketing plus distribution cost (including Federal and state excise taxes). The Federal Energy Administration1) reported that imported crude oil delivered costs (excluding import tariffs) averaged about $12.75 per barrel for the 18 month period ending September, 1975. There is no defensible way to forecast how this price will change between now and 1985. So it will be assumed without justification that the price will not change when measured in constant dollars.

Fortunately, estimates of the volume impact of EPA's regulations are insensitive to refining cost estimates (see above). Consequently, an average refining cost of $2.5 per barrel (about six cents per gallon) will be utilized. This value is consistent with current construction costs and operating costs. This cost can be utilized directly for jet fuel, distillate fuel oil and "other products". For gasoline, the capital charges and operating costs incurred in the conversion of naphtha to gasoline will raise its value to roughly 2 cents per gallon (84 cents per barrel) over other fuel products. (The actual costs for octane generating facilities are closer to 5 cents per gallon. However,

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1) FEA, Monthly Energy Review, November 1975, p. 53.

the lower fuel value of the naphtha feedstock offsets by about 3 cents the relative "cost" of gasoline.)

Because residual fuel oil in the base version of the model expansion contains a considerable quantity of desulfurized material (atmospheric bottoms) it is also appropriate to assign average refining cost to this material. Were asphalt not sold as such, it would have to be sold as (a component of) residual fuel oil, and would have to meet base version sulfur requirements (1.2 percent). Consequently, a reasonable refinery gate price for asphalt is residual fuel oil price less the cost of vacuum bottoms desulfurization to 1.2 percent sulfur. The cost of this process is roughly \$3.5 per barrel1), or 8 cents per gallon. However, the costs of air blowing, heated seasonal storage, blending, etc., necessary to convert vacuum bottoms into marketable asphalt will reduce this price difference by about half.

Estimates of distribution plus marketing costs are based on observations of today's markets. This is an adequate method because of the insensitivity of the analysis to consumer price as demonstrated above. It is estimated that the sum of primary and secondary distribution costs plus service station margins for gasoline total about 13 cents per gallon. Adding the current average Federal/state tax impositions of 12 cents per gallon gives a total cost of 25 cents per gallon from the refinery gate to the automobile tank.

For jet fuel, the difference between the refinery gate price and the price delivered into a commercial airplane is of the order of 3 cents per gallon. For distillate fuel oil, the price is marked up about 8 cents a gallon from the refinery gate to the homeowner's tank. Most residual fuel oil is sold to large consumers. Hence, the difference between refinery gate and consumer price is small - an estimate of 2 cents per gallon appears reasonable. The distribution pattern for asphalt

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1) Part Two, Attachment 2.

is similar to that for jet fuel so the same cost, 3 cents per gallon, will be used. "All other products" include such disparate items as propane sold across the refinery fence to an adjoining chemicals manufacturer with less than one cent per gallon markup over refinery gate cost and lubricating oils sold at service stations for three dollars per gallon over refinery price. Since petrochemical feed stock is the largest single item, an unsupported estimate of three cents per gallon will be used.

Product	Percent of Outturn from New Capacity[1]	Refinery Gate Price In Base Version of Model Expansion (Cents Per Gallon)	Consumer Price (Cents Per Gallon)
Motor Gasoline	20.3	38	63
Jet Fuel	16.2	36	39
Distillate Fuel Oil	25.1	36	44
Residual Fuel Oil	12.0	36	38
Asphalt	5.9	32	35
Other Products (all low sulfur)	20.5	36	39
	100.0		
Weighted average ($\frac{\$12.75 + \$2.5}{42}$ =)		36.2	

2. Estimates of Product Volumes in the Absence of EPA's Regulations

With the exception of gasoline, 1985 U.S. consumption estimates for petroleum products are those shown in Table A-2 of Part Two. The values shown therein were disaggregated from a September, 1974 study by the National Petroleum Council.[2] These forecasts are consistent with Project Independence Report forecasts of total domestic petroleum product consumption.

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1) Chapter II, Section A.

2) Emergency Preparedness: Interruption of Petroleum Imports Into the U.S.

As mentioned, it was felt necessary to modify the NPC gasoline consumption forecast. Because the life cycle of an automobile is much shorter than that of other capital equipment, by 1985 over 80 percent of the vehicles on the road will have been purchased since the OPEC crude price increase. This situation seems to call for use of a long-run elasticity estimate for deriving future gasoline consumption. The computations are shown in Appendix A. The result is to reduce forecast 1985 gasoline consumption from the NPC value of 8.41 million barrels per day to a level of 7.27 million barrels per day.

The 1985 product consumption forecasts from which the EPA volume effects will be computed are then as follows:

Product	Forecast Domestic 1985 Consumption (million barrels per day)
Motor Gasoline	7.27
Jet Fuel (Kerosene Range)	1.52
Distillate Fuel Oil (Including Kerosene)	3.79
Residual Fuel Oil	3.09
Asphalt	0.73
Other Products (all low sulfur)	1.77

C. Volume Effects of EPA's Regulations

In the preceding section prices and volumes that would obtain in 1985 in the absence of EPA's regulations were derived. In this section elasticities will be estimated and the volumetric effects of the regulations computed.

1. Gasoline

In Chapter II it was shown that the refinery gate price for unleaded gasoline must be one cent per gallon higher than that for 96 octane leaded material. There is an additional "cost" to the consumer that is not reflected in this **price.** This is the decrease in fuel efficiency that consumers will observe when they shift from automobiles designed for 96 octane to those designed for 92.

It is important to understand the components of this effect. Conceptually, the penalty attributable to EPA's regulations is the increase in gasoline use that would be required to maintain an unchanged level of performance in controlled versus uncontrolled automobiles that are otherwise identical in the satisfaction they provide to consumers. The penalty is not the change in fuel consumption between two cars that differ only in octane requirements. Rather, the logic is as follows: In order to maintain equal performance with 92 octane as was achieved with 96 octane, automobiles must be equipped with larger engines. Of course, these larger engines require that other parts be larger too to support the additional weight. Catalytic converters also add some weight to cars, requiring marginally larger engines to maintain equal performance. One could argue that automobile manufacturers could redesign cars, substitute lighter materials and take other steps to reduce weight. Such changes must be non-optimal in the absence of control requirements or they would have previously been made. Consequently, they must be considered as a reaction to, and partial compensation for, the added weight (and cost) resulting from EPA's regulations. And, presumably, these "altered" cars are in some sense less desirable to users than those that they would purchase in the absence of EPA's regulations. This argument leads to the conclusion that the proper measure of efficiency loss is between cars which have identical performance characteristics and identical consumer satisfaction.1)

In Part Two it is estimated that the energy penalty associated with EPA's regulations on automobile emissions is about 8 percent. In other words, it will take 108 gallons of 92 octane gasoline to drive the same number of miles that could be driven with 100 gallons of 96 octane gasoline. This is a

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1) Another example: suppose the price of butter rises. Consumers will then purchase less butter, less bread, but more margarine. The loss in consumer satisfaction is more than measured by the reduction in bread consumption. The facts that they may spread butter thinner and also use margarine instead of butter are also measures of **dis**satisfaction and as such, measures of the effect of a change in butter price.

price effect from the consumers viewpoint just as is the one cent per gallon price increase that he will observe on his service station pump. Per mile driven, the consumer will have to purchase 8 percent more gasoline that is one cent per gallon more expensive. In other words, the "price" faced by a consumer of EPA quality gasoline will be: (63 + 1) x 1.08 = 69.1 cents per gallon.

In the Project Independence Report1) an estimate of the price elasticity of demand for gasoline of -.76 is shown for crude oil values ranging from \$4 to \$15 per barrel. The derivation of this elasticity estimate was not fully presented. However, the authors of this study independently estimated demand elasticity by comparing the gasoline economy of automobiles built in Europe with that of cars built in the U.S. Historically gasoline prices have been two to three times greater in Europe than in this country. It was concluded that a long term demand elasticity estimate between about -0.8 and -1.1 could be defended. This datum suggests that the Project Independence Report estimate is reasonable and more likely to be low than high for the long run. Since 1985 consumption will not fully reflect adjustments to long term equilibrium it seems appropriate to use the Project Independence Report estimate as it stands.

The effect of EPA's regulations on gasoline volume can now be computed. The computation proceeds in two steps. First, the effect of gasoline price on mileage driven will be derived. And then these miles will be converted to gasoline volume

The effect of EPA's regulations on miles driven is:

$$M_2 - M_1 = 100 \left[\left(\frac{P_1}{P_2}\right)^{0.76} -1 \right]$$

$$= 100 \left[\left(\frac{63}{69.1}\right)^{0.76} -1 \right]$$

$$= -6.8 \text{ percent}$$

But 8 percent more gasoline is required per mile. Thus, the total effect of EPA's regulations is to increase gasoline

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1) Federal Energy Agency, November 1974, Appendices page 66.

consumption by [1.08 x (1 - 0.068) =] 0.7 percent. As a practical matter, this is essentially no effect at all.

2. Jet Fuel (Kerosene type)

No estimates of the demand elasticity for jet fuel were given in the Project Independence Report. However, one can derive an estimate in the following way: The Civil Aeronautics Board, after much discussion, has accepted in its rate proceedings a demand elasticity estimate for air travel of -0.7. The cost of jet fuel makes up about 18 percent of total airline costs. Hence, 18 percent of -0.7, or -0.13, is an appropriate estimate for the elasticity of jet fuel.

The price increase faced by jet fuel as a result of EPA's regulations was shown in Chapter II to be one cent per gallon. Substituting known values in the demand curve equation leads to an estimate of -0.3 percent as the impact of EPA's regulations on the volume of jet fuel consumed in the U.S.:

$$\frac{Q_2 - Q_1}{Q_1} = \left(\frac{39}{40}\right)^{0.13} - 1 = -0.3 \text{ percent}$$

3. Distillate Fuel Oil

Project Independence Report presents three estimates of the demand elasticity of distillate fuel: for diesel fuel, -0.4; for home heating fuel, -0.6; and for industrial uses, -1.1. The elasticities are presented under the title "Long Run Own - Elasticity . . ." The word "own" implies that the elasticity estimates were derived on the assumption that prices of other fuels remain constant. But EPA's regulations will cause the prices of all petroleum products to increase. If the various products are substitutes for each other, then the "own" demand elasticity is greater than the demand elasticity pertinent for use in this study. This factor is not important in the case of turbine fuel or home heating oil because inter-fuel substitution possibilities are insignificant. But in the case of industrial use of distillate fuel oil, the inter-fuel substitution potential is large and, consequently, the Project Independence Report estimates just discussed are significantly upward biased for use here.

In the case of distillate fuel oil used by industrial and utility consumers, residual fuel oil substitution is a strong possibility. Consequently, the estimate of -1.1 must be disregarded. On the other hand, the estimate of -0.6 for household consumers appears reasonable for use here because interfuel competition is distinctly limited. In fact, high-priced electricity and imported liquified natural gas are the only two substitutes that could become marginally available during the period of this study. Consequently, the estimate of -0.6 will be used as a reasonable average of all consumer uses.

The price increase needed by distillate fuel oil to cover the costs of EPA's regulations was shown in Chapter II to be 1.1 cents per gallon. The relative effect of EPA's regulations on the consumption of distillate fuel oil in the U.S. then, is as follows;

$$\frac{Q_2 - Q_1}{Q_1} = \left(\frac{44}{45.1}\right)^{0.6} - 1 = -1.5 \text{ percent}$$

4. Residual Fuel Oil

Most residual fuel oil is used by electric generating utilities and in the industrial sector. In these uses coal and nuclear power are reasonable substitutes for most installations in the long run. Consequently the prices of these alternates, particularly of coal, set limits on users' willingness to pay for residual fuel oil. As discussed earlier, it appears that the long run delivered supply cost of coal, including all environmental control costs, will be less than half the price of residual fuel oil. Hence, in the long run one must expect considerable substitution to be technically feasible. Relative to this the impact of EPA's regulations on residual fuel oil consumption will be small.

Project Independence Report estimates the own-elasticity of demand for residual fuel in household uses, which presumably includes electricity generated from residual fuel oil, as -0.35. For industrial uses, the estimate is about -1.5. (In both uses, own-elasticity is the relevant measure.) Consumption of residual, including that used for electric generation, is roughly evenly split between these two uses. So, an average value of -0.9 will be utilized.

In Chapter II, the cost impact of EPA's regulations on residual fuel oil was shown to be 1.1 cents per gallon. Hence, the effect of EPA's regulations on consumption of residual fuel oil will be:

$$\frac{Q_2 - Q_1}{Q_1} = \left(\frac{}{39.1}\right)^{0.9} -1 = -2.5 \text{ percent}$$

5. Asphalt

The National Petroleum Council[1] has estimated that the price elasticity of demand for asphalt is 1/8 of the price elasticity of demand for road paving. A reasonable estimate for the latter is -1.0, which would be the value if road-building budgets were fixed. (That is, if the cost of road-building per mile increased by 10 percent, the number of miles paved would decrease by 10 percent.) It is doubtful that road-paving elasticity is really this high. Nevertheless, an estimate of -0.12 will be used for asphalt even though it may be a bit high.

In Chapter II, the price effect on asphalt of EPA's regulations was shown to be one cent per gallon. Hence, the effect on asphalt consumption of EPA's regulations is:

$$\frac{Q_2 - Q_1}{Q_1} = \left(\frac{35}{36}\right)^{0.12} -1 = -0.3 \text{ percent}$$

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1) U.S. Energy Outlook - Energy Demand, 1973, p. 59.

6. All Other Products

This category consists predominantly of petrochemical feedstocks. Naphthas, solvents, and lubricating oil feedstock are also included. Project Independence Report contains no information on these materials. The National Petroleum Council, however, is of more help.1) The NPC concludes that demand for lubricating oils is relatively inelastic. Since feedstock represents a small part of the consumer price of lubricating oil, its price elasticity of demand must be very low.

The NPC states three reasons why they would expect petrochemical feedstock demand to be rather elastic, but never explicitly states an estimate. Given that raw materials represent a substantial percentage of finished chemical prices, and that petrochemical end use products are to a substantial extent substitutable by materials such as wood, glass and metal, it is appropriate to use a near unitary estimate of elasticity. Lacking data, a value of -0.8 will be utilized.

Neither the NPC nor Project Independence Report discuss the elasticity of demand for naphthas and solvents. Since these materials are such a small percentage of the other products category, it is not necessary to develop an estimate.

Because petrochemical feedstocks represent by far the largest fraction of this category, an average elasticity estimate of -0.7 appears appropriate. The price effect of EPA's regulations was shown to be 1.1 cents per gallon in Chapter II. This leads to the following estimate of the quantity effect of EPA's regulations:

$$\frac{Q_2 - Q_1}{Q_1} = \left(\frac{39}{40.1}\right)^{0.7} - 1 = -1.9 \text{ percent}$$

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1) Ibid, pg. 57 and 58.

7. Summary of Volume Effects

Product	Effect of EPA's Regulations On Petroleum Product Consumption In The United States In 1985 Percent	Million Barrels Per Day
Gasoline	+.7	+.051
Jet Fuel	-.3	-.004
Distillate Fuel Oil	-1.5	-.057
Residual Fuel Oil	-2.5	-.077
Asphalt	-.3	-.002
Other Products	-1.9	-.034
Total		-.123

D. Sulfur and Lead

1. Sulfur

As a result of EPA's regulations refineries will recover more sulfur than now. And additional amounts may be recovered incidental to the manufacture of other products, as a result of burning high-sulfur oil in installations equipped with regenerative stack gas cleaning processes. No commercial regenerative plants now exist.

Table IV-4 in Part Two provides a forecast for new Claus plant installations which results in an increased sulfur recovery estimate of roughly 2 million tons in 1977 and almost 3 million tons in 1983.[1] Not all the new Claus plant installations projected for the above time periods should be attributed to EPA's regulations. In fact, the quantity of these installations caused by EPA's regulations can be estimated by adding the following sulfur sources.

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1) As was pointed out in Part Two, an indeterminate fraction of low sulfur residual oil used in the U.S. market may be imported. To the extent that imported low sulfur material made from high sulfur crude is used, the sulfur recovery will take place abroad.

1. Sulfur recovered from reducing average sulfur content of domestically produced residual fuel oil (weighing 350 pounds per barrel) from 1.2 to 0.9 percent:

$$\frac{1{,}416^{1)} \times 10^{3} \times 350 \times .95 \times (.012 - .009) \times 365}{2{,}240 \text{ pounds per long ton}} = 0.2 \text{ million long tons per year}$$

2. Sulfur recovered from reducing average sulfur content of refinery fuel from 1.6 to 0.7:

$$\frac{1{,}288^{2)} \times 10^{3} \times 350 \times .95 \times (.016 - .007) \times 365}{2{,}240} = 0.7 \text{ million long tons per year}$$

3. Sulfur recovered from Claus plant tailgas cleanup which increases recovery efficiency from 95 to 99.5 percent:

$$18{,}457^{3)} \times .81 \times (.995 - .95) \times 365 = 0.2 \text{ million long tons per year}$$

Total 1.1

These numbers represent a small part of the United States' sulfur production which in 1971 was about 120 million tons4). This, in turn, was about 43 percent of world output. In view of the small fraction that the added petroleum refiners' recovery represents of U.S. and world output, it seems unlikely that there will be any impact on sulfur prices or on sulfur recovery. Also, some sulfur recovery in the manufacture of fuel oil for the U.S. market may take place in foreign refineries. This recovered sulfur may not be competitive in the domestic sulfur market.

In addition to the sulfur recoveries discussed above additional amounts may be recovered in coal liquification and gasification plants. But such recoveries will not reach large volumes in the time period covered by this study.

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1) Barrels per day of residual fuel oil - Part Two, Table A-3.

2) 8 percent of crude oil processed in 1985, Appendix A, Exhibit A-2.

3) Capacity of cleanup installations in existing and new refining capacity as developed in Appendix B.

4) *Statistical Abstract of the United States*, 1973, pp. 648,651.

2. Lead

In 1973 the petroleum refining industry purchased about 959 million pounds of lead anti-knock compound valued at about $519 million or 54 cents per pound.[1] This amount of anti-knock compound contained roughly 180 thousand short tons of lead. By 1983 the purchases of lead for anti-knock compound manufacture will be reduced to about 63 thousand tons (if the lead reduction schedule is in effect) or to about 117 thousand tons[2] (if no such schedule is in effect but new automobiles require unleaded gasoline). It should be noted that approximately 20 percent of gasoline output in the post 1983 time period will be leaded grades to supply heavy duty trucks, motor boats, off-highway uses and other markets not covered by EPA's regulations.

Annual lead production in the U.S. is roughly 600 thousand short tons[3] and this represents only about 15 percent of world production. Thus, the reduction in the use of lead by the refining industry implies a reduction in demand of up to about a fifth of current U.S. production, or about three percent of world production. It seems reasonable to expect that consumption of lead for uses other than by the petroleum refining industry will grow between now and 1983. Consequently, the impact on sales will be somewhat smaller percentages than are mentioned above. This contractor has no basis for evaluating the impact of such demand declines on the lead producing industry in the U.S. or abroad.

Lead anti-knock compounds (TEL or TML or mixes of the two) are made by four firms: DuPont, Ethyl, Nalco, and the Houston Chemical Division of PPG. All four firms are well diversified and there is no basis for assessing the impact of reduced anti-knock sales on their total sales or profitability. Aggregate total sales of the four firms in 1974 exceeded $10 billion. So, anti-knock compound sales are roughly 5 percent of their total sales. The reduction in lead compound sales between now and 1983 represents about 3 to 4 percent of their current aggregate total sales. But anti-knock compound sales are a far higher fraction of Ethyl's than DuPont's total sales, and the importance of anti-knock sales to the other two suppliers is not known. It is likely, however, that sales reduction will have differential effects on the four suppliers.

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[1] U.S. Tariff Commission Report: Synthetic Organic Chemicals; U.S. Production & Sales, 1973.

[2] Estimated on the basis of gasoline use forecast developed earlier in this chapter.

[3] 578,500 tons in 1971. Statistical Abstract of the United States, 1973, p. 649.

Raw material costs account for less than one-half of the sales price of anti-knock compounds and the manufacturing process is capital intensive. Consequently, it may be that lead anti-knock sales decreases will have a depressing effect on the profitability of some or all of its suppliers. It is beyond the scope of this study to make an estimate of this effect.

CHAPTER IV

AGGREGATE INDUSTRY IMPACTS

A. Introduction

The purpose of this Chapter is to develop the total impact on the petroleum refining industry of EPA's regulations. Impacts on capital requirements, costs and revenues will be derived. Consideration of differential effects on plants of varying characteristics will be considered in the next Chapter.

As has been true throughout Part Three, the analysis will be based on two key assumptions: 1) that the domestic refining industry will be protected by a sufficiently high tariff that all growth in domestic consumption will be supplied from domestic refineries, and 2) that no price controls are in effect. The latter assumption is necessary because the current price control system may not permit recovery of investments to meet EPA's regulations. In the absence of price controls, the combination of normal price incentives and EPA's regulations would result in the industry investing the required capital.

It will be developed in this Chapter that gross requirements for capital to meet EPA's regulations over the period 1974 to 1983 is about 6.3 billion dollars. Offsetting this is a capital requirements reduction of about 0.4 billion dollars to account for new refinery capacity that would not need to be built because product demands with EPA's regulations are lower than without them. This 0.4 billion dollar reduction should not be viewed as a decrease in the impact of EPA's regulations, or as resulting in an improvement in social welfare due to a lessening in the demands for capital. As was previously discussed, the reduction in the flow of products resulting from a reduction in quantity demanded represents a worsening of the level of consumer-want satisfaction. And the resultant redeployment of capital mitigates, but does not eliminate, this effect.

The net 5.9 billion dollar capital cost of conforming to EPA's regulations represents roughly 1/6 of the replacement value of the present petroleum refining industry. Another way of viewing this 0.7 billion dollar per year requirement is to compare it with average capital expenditures for U.S. refineries in 1973/74 which were 1.4 billion dollars[1]. Total 1974 capital expenditures for the domestic integrated oil industry (including exploration, production, refineries, transportation, distribution and marketing) were 16.6 billion dollars.

Cost data will be accumulated in four segments for each class of EPA regulation: Expenditures in 1974-1977 and in 1978-1983 will be developed for old (existing in 1973) and for new (starting-up in 1974 or later) refinery capacity.

Since needed new refinery capacity depends on EPA's regulations (as derived in Chapter III), determination of new refinery capacity will precede the detailed development of costs and revenues.

B. Impact on Required Growth in Refinery Capacity

EPA's regulations affect the quantity of new refinery capacity in two ways. First, the higher product prices required to justify investments to meet EPA's regulations in refinery expansions will cause less product to be demanded. In Section C.7 of Chapter III this effect was computed to be a reduction of 123 thousand barrels per day in quantity demanded.

The second effect of EPA's regulations is in the opposite direction. It is the increased quantity of crude oil that must be processed to provide the energy needed to operate the additional facilities required by EPA's regulations. This effect must be analyzed in two parts - requirements for existing and for new refinery capacity.

The crude oil processing capacity increment required to provide energy to EPA facilities in existing-in-1973 refineries is not explicitly recognized in Part Two. (However, the full unit costs of the crude oil and its processing are included.) It was not possible to determine in detail the energy impact on existing refineries of EPA's regulations. The relative quantity will be

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1) Chase Manhattan Bank, Capital Investments of the World Petroleum Industry, 1973 and 1974.

less than in new plants, for some energy savings will be experienced when EPA facilities are installed. A considered estimate of this energy requirement is 0.6 percent of intake, or (12,825[1] x 0.006 =) 77 thousand barrels per day of fuel required.

The above effects result in a decrease in the quantity of product demanded of (123 - 77 =) 46 thousand barrels per day, or a decrease in required crude oil processing capacity of:[2]

$$\frac{46}{.92 \times .9 \times .9} = 62 \text{ thousand barrels per stream day.}$$

The net energy cost of conforming to EPA's regulations in refinery capacity expansions is equal to the crude oil processing capacity required in the EPA version of the model expansion relative to the base version. This is an 0.8 percent increase.[3] Crude oil capacity at the beginning of 1983 in the absence of EPA's regulations would be 3,692 thousand barrels per stream day.[4] So the crude oil capacity requirement of EPA's regulations in refinery capacity expansions is (3,692 x 0.008 =) 29 thousand barrels per stream day.

The combined effects of EPA's regulations is a decrease in new refinery capacity requirement of (62 - 29 =) 33 thousand barrels per stream day. Hence, the capacity increase needed with EPA's regulations is (3,692 - 33 =) 3,659 thousand barrels per stream day. This value is the basis upon which all EPA costs for new refinery capacities are computed.

The investment cost for new refinery capacity is about 2,500 dollars per daily barrel of crude oil processing capacity.[5] Hence, the investment requirements for new capacity will be

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1) Appendix A, Exhibit A-2.

2) The denominator contains factors to convert barrels of product manufactured per calendar day into required crude oil processing capacity - see Appendix A, Section 2.

3) 1.4 percent gross increase in capacity less 0.6 percent increase in LPG outturn - Exhibit A-5 versus Exhibit A-4, Appendix A.

4) Appendix A, Exhibit A-3.

5) Turner, Mason and Solomon, private correspondence, July 18,1975.

reduced as a result of EPA's regulations by a net of:

33 x 2.5 = 83 million dollars

This cost savings is the net of a 330 million dollar cost increase for energy manufacturing facilities needed to run EPA installations less a 413 million dollar cost decrease because fewer products will be demanded due to EPA-caused higher prices. As discussed above, this latter cost is not an offset from the viewpoint of consumer welfare.

C. Capital Needs and Annual Costs

1. Water Effluent Control

The costs of conforming water effluent quality to EPA's regulations are developed in Part Two. Since the above forecast of new refinery capacity additions was developed subsequent to the work done in Part Two, it was necessary to adjust the cost estimates for new refinery capacity. This was done by multiplying the original cost estimates by the ratio of revised new refinery capacity additions to original new refinery capacity additions.

Water effluent control costs are:

	Cost - Million Dollars	
	Capital	Annual*
Existing-in-1973 Capacity		
Period 1974 thru 1977	1,610	617
Period 1978 thru 1983	553	834
New-after-1973 Capacity		
Period 1974 thru 1977	217	111
Period 1977 thru 1983	286	230
	2,666	1,064

*Operating costs plus capital charges in last year of period indicated.

2. Airborne Emission Control

a. Hydrocarbon emissions from tanks, loading racks and API separators. In Appendix B it is shown that expenditures for these control requirements are profitable for most existing refinery capacity at today's crude oil prices. For small refineries, however, these items are costly. Consequently, it was necessary to adjust the estimates in Part Two to delete installations that are profitable. These adjustments are shown in Appendix B.

Resultant costs are as follows:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	43	6
Period 1978 thru 1983	11	7
New-after-1973 Capacity		
Period 1974 thru 1977	-	-
Period 1978 thru 1983	-	-
	54	7

b. Emissions from catalytic cracking units. These units emit carbon monoxide and particulates, both of which are subject to EPA's regulations. Carbon monoxide control is achieved by burning it to carbon dioxide. This burning can take place either within the cracking unit regenerator or in an external carbon monoxide boiler. At current energy prices both of these energy recovery options are profitable for essentially all catalytic cracking units. Hence, there is nil cost to the industry for controlling carbon monoxide emissions.

Particulate emission control from catalytic cracking units requires installation of electrostatic precipitators. There are no heat or material recovery credits associated with these units, so their installation in every case is an EPA cost. Costs for existing refineries are developed in Appendix B. Costs for new capacity reflect only known catalytic cracking expansions.[1]

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	127	39
Period 1978 thru 1983	32	49
New-after-1973 Capacity		
Period 1974 thru 1977	6	2
Period 1978 thru 1983	-	2
	165	51

c. Sulfur Oxide Emission Control. There are three cost items to consider in this category. Installation and operation of the following facilities will be needed:

1. Amine and Claus units to remove hydrogen sulfide from refinery byproduct gas fuel and convert it to sulfur.
2. Claus plant effluent tailgas cleanup units.
3. Desulfurization units to reduce the sulfur content of liquid refinery fuel (and associated amine/Claus/tailgas units to recover and convert the hydrogen sulfide produced).

New refineries will clearly have to be self-sufficient in energy. The situation for existing refineries is more complex. About half of the energy consumed by refineries in 1973

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1) 136 thousand barrels per day (Appendix A, Section 3).

was obtained from outside sources, predominantly natural gas.[1] By 1983 natural gas supply for refineries will be severely curtailed. It will be necessary to replace this short-fall with own-manufactured liquid fuel. The cost of desulfurizing the replacement fuel should not be considered to be caused by EPA's regulations. Rather, this cost is a result of Federal natural gas policies.

EPA's regulations require that the sulfur content of refinery fuel in existing refineries be reduced to levels stipulated in State Implementation Plans. In refinery capacity expansions fuel sulfur content must not exceed Federal standards for large new stationary sources, and may be further restricted by State Implementation Plans. A plant-by-plant survey would be required to develop precise requirements for fuel sulfur content. Such a study is beyond the scope of this work.

For refinery gas fuel the data and premises developed in Chapter IV of Part Two are useful. These show that all new capacity, and almost all existing refineries, will require amine/Claus/tailgas cleanup units. The amine/Claus plant status of existing refineries is also reviewed in Chapter IV of Part Two. These data show that many amine plants have not yet been provided with companion Claus units. Table IV-15 in Part Two shows that the installation of Claus plants in refineries already equipped with amine facilities is profitable in most cases. Because it is profitable, the cost of installing Claus plants in refineries already equipped with amine facilities is not a cost of EPA's regulations.

Details of the adjustments to Part Two costs just discussed, and derivations of the costs of amine/Claus/tailgas installations in new and existing refineries are presented in Section 3 of Appendix B. Total capital cost of these installation

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1) Sobotka & Company, Industrial Energy Study of the Petroleum Refining Industry, May 20, 1974.

is 389 million dollars; annual cost in 1983 is 122 million dollars.

Chapter V of Part Two shows that, in order to conform to EPA's regulations, the sulfur content of liquid fuel in existing refineries will have to average 0.7 percent by weight. The average sulfur content of liquid fuels used in refineries in 1973 is estimated to have been about 1.6 percent.1) Consumption was 136 thousand barrels per day.2) Consumption in this capacity in 1983 will be about 160 thousand barrels per day.3) The cost of conforming to EPA's regulations in existing-in-1973 refineries, then, is the cost of desulfurizing 160 thousand barrels per day of refinery liquid fuel from 1.6 percent to 0.7 percent sulfur. It appears that atmospheric bottoms desulfurization from 2.9 percent sulfur to 0.5 percent sulfur is the most appropriate process to use for costing this requirement. The volume of atmospheric bottoms needed to be desulfurized to achieve an 0.7 percent sulfur refinery fuel pool is:

$$160 \times \frac{(1.6 - 0.7)}{(2.9 - 0.5)} = 60 \text{ thousand barrels per day}$$

Using an average of the unit costs shown on page V-13 of Part Two, investment costs will be 107 million dollars and annual cost in 1983 will be 49 million dollars. Further details of this derivation are shown in Section 3 of Appendix B.

Chapter V of Part Two also shows that the sulfur content of liquid fuel in refinery expansions must average 0.7 percent. The relative volume of liquid fuel is 7.2 percent of crude oil intake into refinery expansion4), or 213 thousand barrels per day.

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1) Table V-5 of Part Two.

2) Bureau of Mines, Mineral Industry Surveys for 1973.

3) Assuming 4 percent liquid fuel required by increased runs in existing capacity.

4) Appendix A, Exhibit A-5B.

Since only post-1973 costs of EPA's regulations are relevant here, the base sulfur level from which EPA costs are measured is 1.6 percent, the level observed in 1973. It appears that vacuum bottoms desulfurization may be utilized for refinery fuel desulfurization in refinery capacity expansions. In the model expansion feedstock to desulfurization is 4.3 percent sulfur and product is 1.0 percent sulfur. The volume of feedstock to be physically processed to reduce refinery fuel sulfur content from the 1973 value (1.6 percent) to the 0.7 percent requirement goal is:

$$212 \times \frac{(1.6 - 0.7)}{(4.3 - 1.0)} = 58 \text{ thousand barrels per day}$$

Attachment 2 at the end of Part Two provides unit costs for this type plant. Applying the Attachment 2 unit costs to the feedstock volume to be processed yields 171 million dollars cumulative capital investment by 1983 and an annual cost in 1983 of 83 million dollars. Further details of this derivation are shown in Section 3 of Appendix B.

The total costs of controlling sulfur oxide emissions from petroleum refineries are:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	303	100
Period 1978 thru 1983	117	144
New-after-1973 Capacity		
Period 1974 thru 1977	190	85
Period 1978 thru 1983	57	110
	667	254

3. Product Quality Requirements

a. Low sulfur residual fuel oil. Page V-11 in Part Two indicates that the sulfur content of the composite U.S. fuel oil pool must be reduced from an average of 1.2 percent weight in 1973 to 0.9 percent in 1983. It was determined that imported and domestically produced residual fuel oil each averaged about 1.2 percent sulfur in 1973.1)

The residual fuel oil pool in 1983 will be supplied from three sources:

new domestic refining - 363 thousand barrels per day2)
existing-in-1973 domestic refining - 1,053 thousand barrels per day2)
imports and other supply - 1,677 thousand barrels per day3)
3,093

In Chapter II, Section A, it was reasoned that new refinery capacity will manufacture residual fuel oil products averaging 0.5 percent sulfur content. So the balance of the supply (existing domestic plus imports) must average about 1.0 percent sulfur content to create a composite pool of 0.9 percent sulfur.

Next will be developed the investment and annual costs for residual fuel oil desulfurization required of domestic refineries, new and existing. The costs to foreign refineries for reducing the sulfur content of their exports to the U.S. from

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1) Bureau of Mines, Mineral Industry Surveys, Availability of Heavy Fuel Oils by Sulfur Levels, December 1973, restated in Part Two, Table V-5.

2) Appendix A, Exhibit A-2.

3) Part Two, Table A-3.

1.2 to 1.0 percent are not impacts on the U.S. refinery industry.

As was so for refinery fuel sulfur reduction, it is reasoned that vacuum bottoms desulfurization will be utilized for residual fuel oil sulfur control in refinery capacity expansions. Arabian feedstock to desulfurization is 4.3 percent sulfur and product is 1.0 percent sulfur. The volume of feedstock to be physically processed to reduce residual fuel oil sulfur content from the 1973 value (1.2 percent) to the 0.5 percent requirement is:

$$363 \times \frac{(1.2 - 0.5)}{(4.3 - 1.0)} = 77 \text{ thousand barrels per day}$$

Attachment 2 at the end of Part Two provides unit costs for this type plant. Applying the unit costs provided in Attachment 2 to the feedstock volume to be processed yields 227 million dollars cumulative capital investment by 1983 and an annual cost of 111 million dollars. Expenditures are assumed to occur in proportion to the respective rates of new refinery capacity installations, i.e., 77.1 percent in the 1973 through 1977 time period.

Existing domestic refineries must reduce the average sulfur content of their residual fuel oil production from 1.2 to 1.0 percent. It is reasoned that desulfurization of atmospheric bottoms from 2.9 percent sulfur feedstock to 0.5 percent product will be the typical approach. The volume to be physically processed is:

$$1{,}053 \times \frac{(1.2 - 1.0)}{(2.9 - 0.5)} = 88 \text{ thousand barrels per day}$$

Multiplying this volume by the average of the unit costs provided on Page V-13 of Part Two yields 158 million dollar investment by 1983 and annual costs of 73 million dollars. It is assumed that 50 percent of these costs will be expended during the 1973-1977 time period.

The total costs for U.S. refineries to meet EPA's regulations for the sulfur content of residual fuel oil are:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	79	36
Period 1978 thru 1983	79	73
New-after-1973 Capacity		
Period 1974 thru 1977	175	86
Period 1978 thru 1983	52	111
	385	184

b. Lead in gasoline. The EPA regulation that requires a phased reduction in the lead content of leaded gasoline is the subject of legal challenges. The outcome of this litigation is uncertain: For this impact analysis it has been assumed that the phasedown schedule[1] will be affirmed, but delayed by two years.[2]

The total impact of unleaded gasoline regulations will not be realized until almost all vehicles that are able to use leaded material have been retired. This will not occur until after 1985. However, since the shift to unleaded is inevitable, refiners will make foresighted investments to eliminate lead. That is, when a refinery is faced with the installation of new equipment to permit unleaded gasoline manufacture, it is likely that the investment will be sized for the ultimate volume of unleaded gasoline expected. Based on this reasoning the 1983 cost impact of lead regulations is evaluated herein on the basis of the forecast 1985 leaded/unleaded ratio (20/80).[3]

The EPA regulations that require refineries to provide 92 octane unleaded gasoline in lieu of 96 octane leaded material impact existing refinery capacity substantially but new capacity hardly at all. In Chapter II, Section B.3. it was shown that the annual cost of the model expansion was the same whether 96 octane leaded gasoline (base version) or 92 octane unleaded gasoline (EPA version) was manufactured.[1] However, the investment cost of the EPA version is higher because reformer size and severity must be increased, and slightly more crude oil must be processed. In Appendix B, it is shown that an aggregate of 155 million dollars will be required by new refinery capacity during the 1974/1983 period to conform to EPA's lead-in gasoline regulations.

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[1] Part Two, Page V-4.

[2] This should not be taken to represent an EPA policy intention.

[3] Turner, Mason and Solomon, private communication, June 20, 1975.

For existing refineries there is no known study that can be used directly to determine the impact of EPA's lead regulations. Pages V-2 and V-3 in Part Two contain a discussion of the known studies. (The Phase II study for EPA mentioned there has not yet been published). Lacking directly applicable work, it was necessary to modify the updated Turner, Mason and Solomon (TM&S) study reported in Part Two, page V-4.

A detailed description of the cost derivation is shown in Appendix B, Section 4. For investment cost, the results of the one TM&S model analysis that kept gasoline outturn constant were scaled to represent the 1973 industry. Aggregate investment requirements for 1974/1983 are 1,850 million dollars.

A similar approach could not be used for annual cost. Rather, this was derived by reasoning as follows: It was shown above that the annual cost (operating cost plus capital charges) less lead purchase credits) of EPA's lead regulations in new refinery expansions is nil. The operating cost (labor, catalyst, fuel, etc.) and purchased antiknock savings of lead reduction should be about the same in existing refineries as in new capacity.

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1) The higher capital charges and operating costs in the EPA version are equal to lead antiknock purchase costs in the base version.

Hence, the annual cost of lead reduction in existing refineries is approximately equal to the capital charges incurred by the excess of retrofit investment cost over new capacity investment cost. Total lead control retrofit investment cost was shown above to be 1,850 million dollars for existing refineries (with 14,250 thousand barrels per calendar day capacity).[1] And expansion capacity cost is 156 million dollars (for 3,293 thousand barrels per calendar day capacity). Consequently, the excess cost of retrofitting is:

$$1{,}850 - 156 \left(\frac{14{,}250}{3{,}293}\right) = 1{,}175 \text{ million dollars}$$

The annual cost associated with this capital investment is 303 million dollars per year. That is, the annual cost in 1985 of EPA's lead-in-gasoline regulations to existing-in-1973 refineries will be 303 million dollars.

(Net) costs of EPA's lead regulations are summarized in the following table:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	1,091	107
Period 1978 thru 1983	759	303
New-after-1973 Capacity		
Period 1974 thru 1977	120	-
Period 1978 thru 1983	36	-
	2,006	303

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1) It is correct to relate lead control costs to crude oil volume rather than gasoline volume. This is because only the light naphtha plus catalytic reformate portion of the gasoline pool (which is proportional to crude oil runs) must be upgraded when lead is removed; the rest of the pool (primarily manufactured via such conversion processes as catalytic cracking and alkylation) will average about 96 leaded, 92 clear octane.

4. Total Costs

The total costs of EPA's petroleum refining industry regulations are summarized in the following table:

	Cost - Million Dollars	
	Capital	Annual
Existing-in-1973 Capacity		
Period 1974 thru 1977	3,253	905
Period 1978 thru 1983	1,551	1,410
New-after-1973 Capacity		
Period 1974 thru 1977	708	284
Period 1978 thru 1983	431	453
	6,273 1)	1,863

Over the 9-year period 1974/1982, capital expenditures for conformance with EPA's regulations average $0.7 billion per year. This is 50 percent of average 1973/1974 capital expenditures for U.S. refineries ($1.4 billion per year).2)

D. Recovery and Absorption of EPA's Costs

The extent to which the petroleum refining industry will recover the costs of EPA's regulations depends on the relative costs of conforming new refineries and existing refineries. To the extent that the costs of conforming an existing refinery to EPA's regulations are less than the cost of conforming new capacity , the price increases that will occur will create economic rent for the plant. Conversely, if existing plant costs are greater than those for new capacity, the existing plant capital value will decline by the extent of the difference.

New refinery capacity will be neither advantaged nor disadvantaged by having to conform to EPA's regulations. This is so because new refineries will only be built if the product

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1) Includes 330 million dollars for facilities to provide energy to operate EPA installations - this Chapter, Section B.

2) Chase Manhattan Bank, op. cit.

price structure fully reflects EPA costs. (And, any period of unjustifiably high prices will stimulate new entrants who will soon pull the price level down to or below long run supply cost.)

The amount of EPA costs recovered by existing refineries will equal the volume of products manufactured in these plants in 1983 times the price increase caused by EPA's regulations. With one exception, existing refineries will observe the same product price increases as were derived for expansions in Chapter II. The exception is residual fuel oil. It will be recalled that refinery capacity expansions are forecast to manufacture residual fuel oil with a sulfur content of 0.5 percent. But existing refineries are expected to manufacture a 1.0 percent sulfur product. The market price difference between these two grades will reflect the long run cost of desulfurizing Arabian residual fuel oil. This is about one dollar per barrel per percent sulfur removed.1) That is, the higher sulfur content residual fuel oil manufactured in 1983 in existing-in-1973 refineries will sell for fifty cents per barrel less than the lower sulfur product manufactured in expansions.

It will be recalled that product volumes to be manufactured in 1983 in existing-in-1973 refineries are greater than these refineries manufactured in 1973. This reflects an increase in utilization of calendar day capacity to 90 percent.

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1) Part Two, Page V-13

Recovery of EPA costs can now be computed:

Recovery of EPA Costs by Existing-in-1973 Refineries

	Product Outturn In 1983[1] (Million Barrels)	EPA Price Increase	
		Dollars Per Barrel[2]	Million Dollars Per Year
Gasoline	2,379	0.42	1,000
Kerosene Jet Fuel	317	0.42	133
Distillate Fuel Oil	1,012	0.46	466
Residual Fuel Oil	384	(0.04)	(15)
Asphalt	188	0.42	79
All Other Marketed Products	717	0.46	330
Total	4,997		1,993

The difference between this cost recovery and the annual EPA cost in 1983 of existing-in-1973 refineries is a (1.993 - 1.410 =) 0.6 billion dollars per year gain. That is, cash flow before tax for these plants will increase by 0.6 billion dollars per year, or about 11 cents per barrel crude oil processed.

The EPA impact on existing-in-1973 refineries is a gain because the cost of conforming to EPA's regulations in these plants is, on average, less than it is in new capacity. And it is the new capacity costs that determine product prices. The cost advantage of existing refineries of eleven cents per barrel is a net result of advantages and disadvantages in the different areas regulated by EPA. One area will be worked out in detail to show the methodology. The other areas will then be summarized.

It is shown in Section C.3. above that, in new capacity expansions, refinery fuel sulfur content must be reduced from 1.6 to 0.7 percent sulfur content. Also liquid fuel is 7.2 percent

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1) Output in 1983 identical to output in 1985 (Appendix A, Exhibit A-2).

2) Chapter II Section C (except residual fuel oil discussed above).

of crude oil intake. These factors led to an estimate of unit annual cost of seven cents per barrel crude oil processed.[1)]

In existing-in-1973 refineries, refinery fuel sulfur content is also reduced from 1.6 to 0.7 percent sulfur, but liquid fuel is only 1.1 percent of crude oil. So, annual cost in 1983 was estimated to be 49 million dollars,[2)] and unit cost is:

$$\frac{49}{4{,}681^{3)}} = \text{one cent per barrel crude oil produced}$$

So, relative to expansions, existing-in-1973 refineries are cost-advantaged by EPA's sulfur oxide emission regulations for refineries by six cents per barrel crude oil processed.

Existing-in-1973 refineries are also cost-advantaged relative to expansions:

1. By about seven cents per barrel crude oil due to EPA's regulations on sulfur in residual fuel oil. Less sulfur reduction is expected for existing refineries and residual fuel oil is a lower proportion of product mix.

> Note: Existing refineries also receive lower unit revenues for their higher sulfur product. This was shown in the cost-recovery table above. But per barrel of crude oil, existing refineries are overall net advantaged.

2. By about four cents per barrel crude oil due to EPA's regulations on effluent water. This advantage is a reflection of the degree of conformance to regulations already achieved

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1) Chapter II, Section B.4.

2) Chapter IV, Section C.3.

3) 12.825 million barrels per day processed (Appendix A, Exhibit A-2) x 365 = 4,681 million barrels per year.

by existing refineries. That is, expansions have relatively farther to go to conform than does the average of existing refineries.

Existing-in-1973 refineries are cost-disadvantaged relative to expansions:

1. By about six cents per barrel crude oil due to EPA's regulations on lead in gasoline. It will be recalled that these regulations have nil cost impact on expansions.

2. By about one cent per barrel crude oil due to EPA's regulations on particulate emissions from catalytic cracking units. Most expansions have no such units.

It is emphasized that the cost effects just discussed are measured between the model expansion and the average of the existing-in-1973 industry. Clearly costs and revenues will vary widely among refineries. Notably, small refineries will be relatively disadvantaged. This is the subject of Chapter V. Some larger refineries may also be disadvantaged. But the value of a large refinery is so high that it is inconceivable that any will be closed because of the costs of meeting EPA's regulations. (Of course, there could always be special cases such as, for example, a refinery site so small as to preclude installation of mandatory water treating facilities. But no such case is known and it is unlikely that one exists.)

An exogenous development of the past few years has served to insulate existing plants from the effects of EPA's costs. The development is refinery construction cost inflation. From 1970 to 1975, refinery construction costs increased at a rate far in excess of the general inflation rate. The effect of this development has been to increase the value of refineries built at old, lower cost.[1) The magnitude of this increase is large; the refinery construction cost index has increased by roughly 50 percent more than the implicit GNP price deflator.[2)

E. Impact on Capital Needs for Growth

In Section B of this chapter it was shown that EPA's regulations will reduce the need for capital for refinery expansion by a net of about 0.1 billion dollars below what would otherwise be required. It is important to note that the 0.4 billion dollar cost saving component of this net amount does not represent a lessening of the real cost of EPA's regulations. The impact of increased product prices is to reduce the quantity of products demanded. And consumers are made worse off for having to choose a new consumption pattern. So, while it is true that less "capital" will be needed by the petroleum refining industry as a result of EPA's regulations, this decrease is accompanied by a lessening of consumer satisfaction.

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1) It is noted that the Arco refinery at East Chicago and The Refinery Corporation plant at Denver have recently changed hands at prices in the range of $500 to $750 per daily barrel. These depressed values reflect the price and profit controls that will be in effect until mid-1979 under the Energy Policy Conservation Act, and general uncertainty about possible long run Government policy developments, e.g., functional dismemberment, public utility status, etc.

2) Turner, Mason & Solomon, private correspondence, November, 1975.

F. Capital Requirements of EPA's Regulations Compared to Total National Capital Availability

Capital expenditures in the U.S. during the 1974/83 period will average roughly 150 billion dollars per year.1) Compared to this the net capital requirements for conforming the petroleum refining industry to EPA's regulations (0.7 billion dollars per year) is trivially small. The reader is, however, referred to a study of the construction industry2) for a thorough discussion of the distributive effects of capital demands placed both on the capital markets and on the construction industry by EPA's regulations for all industry and Government.

G. Employment Effects

Implementation of EPA's regulations will increase employment in the petroleum refining industry relative to the level that would have occurred in the absence of EPA. Operators and maintenance personnel will be required for effluent treating facilities and new desulfurization and catalytic reforming units.

A detailed study of increased employment was not made. (Had a significant number of plant abandonments been indicated, detailed research would have been undertaken to assess employment effects.) A rough approximation of the employment increase can be derived from the not unreasonable assumption that employment is proportional to capital investment (in constant dollars).3)

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1) The Impact of Environmental Regulations on Capital Markets and on Industry Capital-Raising Problems, Environmental Protection Agency, January, 1976.

2) Stephen Sobotka & Company, The Economic Impact on the Construction Industry of Additional Demand Caused by New Environmental Protection Standards, EPA Contract No. 68-01-0554, December 29, 1972.

3) Such a relationship was utilized as the basis for several of the industry total cost estimates derived in Part Two.

Refinery employment in 1973 was about 89,000.1) Replacement value of the 1973 industry (in 1974 dollars) was roughly 39 billion dollars.2) Net capital requirements over the 1974/1983 period to meet EPA's regulations are six billion dollars.3) A first approximation, then, of the employment increase associated with implementation of EPA's regulations on the petroleum refining industry is:

$$89 \times \frac{6}{39} = 14 \text{ thousand employees}$$

This is a highly uncertain forecast. And it ignores technological improvement which, in the past, has maintained approximately constant employment despite rising output. Nevertheless, there is no doubt that implementation of EPA's regulations in this industry will lead to significantly increased employment.

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1) Production and related workers - Part One, Exhibit 13.

2) 15.8 million barrels per stream day capacity (Exhibit A-2) times 2.5 thousand dollars per daily barrel. (The existing number and size of units would cost between two and three thousand dollars per daily barrel of crude capacity tc replace.)

3) Sections B and C.5. above.

CHAPTER V

DIFFERENTIAL IMPACTS DUE TO REFINERY SIZE AND CONFIGURATION

In Chapter II the impact of EPA's regulations on the cost structure of a model refinery expansion was developed. It was shown there that the annual cost increases resulting from EPA's regulations will be about 39 cents per barrel of crude oil in 1983. For capacity expansions of the type that will set industry prices in the period under study this cost increase will be exactly recovered by product price increases.

In the preceding Chapter the impact of EPA's costs on the aggregate value of the existing-in-1973 refining industry was developed. It was concluded that, on average, the capital value of the industry was slightly enhanced by EPA's regulations. In this Chapter a segment of the industry will be examined in greater detail to determine if any of these plants will be sufficiently impaired to prejudice their viability. The segment to be studied is 89 of the smallest refineries in the United States. This segment includes all but eleven of the plants with less than 20,000 barrels per day of capacity. (The eleven excluded plants are those for which waste water discharge rates were not available.)

Because it was concluded in Chapter IV that there would be no aggregate industry capital impairment, there was no need to investigate the larger, more viable, segment of the refining industry in detail.

A. Methodology

EPA's regulations will impact existing small refineries in two ways. The refineries will face expenditures to conform with EPA's regulations. Offsetting this, however, will be the product price increases derived in Chapter II. The analysis of small refineries, then, will consist of determining the net of EPA costs and EPA-induced price increases for each small plant. The net cost (benefit) for each plant will then be compared against the cash income before tax that would be earned by the plant in the absence of EPA's regulations. If EPA net cost exceeds cash income before tax, the plant will most probably have to shut down. Conversely, if EPA cost is less than cash income, the plant will clearly have an economic incentive to continue operation.

B. Net EPA Costs for the Small Refineries

A series of prototype model refineries was defined so that the effects of processing configuration and capacity on EPA costs could be determined. The following processing configuration classifications were considered:

"T"-type - topping plants[1] processing low-sulfur crude oils into low-sulfur residual and distillate fuel oils, and naphtha jet fuel.

"A"-type - topping plus vacuum distillation to process high-sulfur crude oils into asphalt, high-sulfur distillates, and naphtha jet fuel.

"R"-type - topping plus catalytic reforming to process low-sulfur crude oils into gasoline and low-sulfur fuel oils.

"C"-type - topping plus catalytic reforming plus cracking (catalytic, hydro or thermal) to process low-sulfur crude oils into gasoline and low-sulfur fuel oils.

Processing capacities of 2.0, 6.0 and 18.0 thousand barrels per day were considered.

Assumed crude oil quality and estimated product yield structure for each prototype configuration are as follows:

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1) "Topping" is crude oil distillation at essentially atmospheric pressure.

	Processing Configuration			
	"T"	"A"	"R"	"C"
Crude Oil Quality				
Gravity, degrees API	40	25	40	40
Sulfur Content	low	high	low	low
Product Yields percent by volume of crude oil processed				
Gasoline[1)]	-	-	35	63
Naphtha Jet Fuel	44	21	-	-
Distillate Fuel Oil	16	-	22	19
High Sulfur Distillate	-	24	-	-
Residual Fuel Oil	37	-	37	12
Asphalt	-	50	-	-
Internally Consumed	3	5	6	8
Processing Gain	-	-	-	(2)
Total	100	100	100	100

The 89 small refineries for which water effluent flow rates were available were each assigned to one of the prototype classes. There are 28 "T"-type topping plants; 20 "A"-type asphalt plants; 19 "R"-type reforming plants and 22 "C"-type plants containing cracking facilities (14 catalytic, 6 thermal cracking and/or coking, 2 hydrocracking). Product yield structure and crude type for each class were assumed to be identical to those derived for the prototypes. This assumption determined the air emission control and product quality requirements (unleaded gasoline and low-sulfur residual fuel oil) for each refinery. Size-dependent annual costs for conforming to these regulations were assigned to each refinery on the basis of the

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1) Excludes natural gas liquids normally purchased and blended. These would add an additional 5 percent to total input and to gasoline outturn for "R" plants and 7 percent for "C" plants.

prototype studies described above (and detailed in Appendix C). Water effluent control costs were assigned to each refinery based on actual 1973 water effluent flow rate[1] and the (flow-dependent) costs of conforming the quality and quantity of this effluent to EPA's regulations. These costs are developed in Appendix C from data presented in Part Two.

The principles underlying the determination of the EPA costs of sulfur control require explanation. One of the three sulfur control costs is straightforward - cleanup of Claus plant effluent gas. This is clearly a cost of EPA's regulations. The other two sulfur control costs are those associated with refinery fuel sulfur regulations and low-sulfur residual fuel oil product.

In 1973 the average sulfur content of residual fuel oil produced in U.S. refineries was about 1.2 percent[2]. Refinery liquid fuel averaged 1.6 percent[3]. By 1983 residual fuel oil will need to be reduced to 1.0 percent[4] in existing-in-1973 refineries and refinery fuel to 0.7 percent[5]. The costs of reducing residual fuel oil from 1.2 to 1.0 percent sulfur and refinery fuel from 1.6 to 0.7 percent are attributable to EPA's regulations. But, in the context of this study, the cost of achieving 1.2 percent sulfur in 1973 is not an EPA cost.

It is important to understand the concept that the higher costs (relative to high-sulfur crude oils) of the low-sulfur crude oils needed by existing small U.S. refineries to meet 1973 product sulfur requirements are not costs assignable to EPA's regulations. The reason is that sulfur-dependent crude

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1) National Commission on Water Quality, Petroleum Refining Industry-Technology and Costs of Wastewater Control, Appendix B, January, 1975.

2) Part Two, Table V-5.

3) Ibid.

4) Chapter IV, Section C.3.a.

5) Ibid, Section C.2.c.

oil price differentials will develop in the world market (from sulfur oxide limitations imposed by European and Japanese environmental protection authorities) independent of actions taken by the United States EPA. And world crude price differentials will determine the differentials paid by U.S. refineries. So, although an increase in the price differential between low- and high-sulfur crude oils is a reflection of (international) environmental concerns, it is not a result of U.S. EPA actions.

In the long run, the price difference between low-sulfur crude oils and high-sulfur crude oils on the international market will tend to the value that would cause the owner of an existing European (or Japanese) refinery to be indifferent as to which he purchases.[1] The owner, when faced with a requirement to make lower sulfur residual fuel oil, may leave his refinery as it is and process low-sulfur crude oil. Alternatively, he can equip it with residual fuel oil desulfurization and sulfur recovery facilities and process high-sulfur crude oils. If the high- versus low-sulfur crude oil price differentials are below the costs of desulfurization, all refineries would choose to process low-sulfur crude oils. But there is not nearly enough low-sulfur crude oil to meet predicted world product demand. Hence, for the market to clear, price differentials must rise to the level of indifference to owners of consumer-country refineries.

Small refinery prototype processing configurations "T", "R", and "C" were premised to utilize low-sulfur grades of crude oil to meet 1973 product quality requirements. This is a rational premise, because the historical price differentials between high- and low-sulfur crude oils were generally too small to justify the high unit cost of installing corrosion resistant

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1) It is appropriate to base this derivation on existing refineries in consuming countries because most new non-U.S. refineries to be built during the next decade will probably be in OPEC countries. And, as previously discussed, OPEC member pricing decisions may not reflect true refining costs.

metallurgy and product desulfurization facilities in small refineries. Also most small refineries are so located that they have good access to (formerly plentiful) U.S. low sulfur crude oil supplies.

In order to meet 1983 regulations small U.S. refineries will need to process still lower sulfur grades of crude oil than they used in 1973. Because they will be lower in sulfur, these grades will be more expensive. It is estimated (in Appendix C, Section 3) that the price of crude oil from which 1983 quality residual fuel oil can be made and refinery fuel sulfur standards satisfied will average about 12 cents per barrel higher than the price for 1973 quality crude oil. This cost differential is clearly attributable to EPA's regulations.

Small "A" type asphalt refineries are premised to process high sulfur crude oil for reasons of asphalt product quality so they will not face relative crude price increases. However, in addition to asphalt and naphtha jet fuel, "A" plants manufacture a high sulfur heavy distillate with physical properties intermediate between distillate and residual fuel oils. This material will not conform to EPA's sulfur content regulations. The cost estimate for desulfurizing this distillate was based on transporting it to a large refinery for processing. Cost of this method is estimated to average 21 cents per barrel crude oil processed in "A" plants.1)

> NOTE: A significant cost that will be faced by many small (and large) refineries is the cost of replacing natural gas with alternative low sulfur own-manufactured fuels. This cost is not an EPA cost because it arises from policies that have nothing to do with EPA.

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1) Appendix C, Section 3.c.

> Moreover, except for "A"-type plants, there are no additional costs to meet sulfur requirements for the replacement refinery fuel. This is because the crude oil quality needed to meet residual fuel oil sulfur requirements will also yield conforming refinery fuel.

Net EPA cost is the cost of conforming to water, air and product quality regulations less the increased revenue received due to product price increases caused by EPA's regulations. The detailed methods used to estimate net EPA costs are developed in Appendix C. Revenue increases are computed (in Section 4 of Appendix C) from the product price changes developed in Chapter II.

Net EPA costs for the 89 small refineries are shown in Exhibits V-1 through V-4. In order to mask the identity of specific plants, capacities are stated in classes. Class boundaries are: 0.1 - 3.0, 3.1 - 7.0, 7.1 - 12.0 and 12.1 - 20.0 thousand barrels per calendar day.

The Exhibits show that about half of the simple "T" and "A"-type plants will be net cost-advantaged by EPA's regulations. But, because of high lead-in-gasoline control costs, all "R" and "C"-type plants will be net disadvantaged. The Exhibits also show the very large variation in water effluent control costs faced by these plants - from nil to 45 cents per barrel crude oil. The costs shown reflect complete conformance to BATEA requirements.

C. Refinery Cash Flows in the Absence of EPA's Regulations

The revenue and cost elements needed to derive cash income before tax ("cash flow" hereafter) for a refinery include product yields, product prices, cash operating cost, and crude oil cost. Product yield structures have been premised for the

EXHIBIT V-1

NET COST OF EPA'S REGULATIONS

"T" Type Refineries

Capacity Range Thousand Barrels Per Day	Cents Per Barrel Crude Oil Processed: EPA Costs: Water	Airborne	Crude Price	EPA Revenue	Net EPA Cost Increase
3-7	37	5	12	(28)	26
3-7	36	5			25
3-7	35	3			22
3-7	34	4			22
3-7	34	3			21
7-12	31	3			18
3-7	30	4			18
12+	21	1			6
3-7	18	4			6
12+	19	2			5
3-7	7	5			(4)
12+	7	2			(7)
3-	0	9			(7)
3-	0	10			(6)
3-	0	7			(9)
3-	0	7			(9)
3-	0	7			(9)
3-	0	7			(9)
3-	0	7			(9)
3-	0	7			(9)
3-	0	6			(10)
3-	0	6			(10)
3-	0	5			(11)
3-7	0	5			(11)
7-12	0	2			(14)
7-12	0	2			(14)
7-12	0	2			(14)
12+	0	2			(14)

EXHIBIT V-2

NET COST OF EPA'S REGULATIONS

"A" Type Refineries

Capacity Range Thousand Barrels Per Day	Cents Per Barrel Crude Oil Processed				
	EPA Costs				
	Water	Airborne	Exchange Distillate	EPA Revenue	Net EPA Cost Increase
3-	41	4	21	(32)	34
3-	39	4	↓	↓	32
3-7	37	3	↓	↓	29
3-7	36	4	↓	↓	29
3-7	35	3	↓	↓	27
7-12	32	2	↓	↓	23
7-12	32	1	↓	↓	22
7-12	31	2	↓	↓	22
3-	28	4	↓	↓	21
3-7	28	3	↓	↓	20
3-7	25	3	↓	↓	17
12+	23	1	↓	↓	13
7-12	22	1	↓	↓	12
3-7	0	3	↓	↓	(8)
3-7	0	3	↓	↓	(8)
7-12	0	2	↓	↓	(9)
7-12	0	2	↓	↓	(9)
7-12	0	1	↓	↓	(10)
12+	0	1	↓	↓	(10)
12+	0	1			(10)

EXHIBIT V-3

NET COST OF EPA'S REGULATIONS

"R" Type Refineries

Capacity Range Thousand Barrels Per Day	Cents Per Barrel Crude Oil Processed					
	EPA Costs					
	Water	Airborne	Lead	Crude Price	EPA Revenue	Net EPA Cost Increase
3-7	39	7	39	13	(27)	71
3-7	37	5	35			63
3-7	35	5	34			60
3-	22	9	42			59
3-7	34	4	33			57
3-7	35	4	32			57
3-7	28	6	36			56
3-	0	15	52			53
7-12	32	3	31			52
7-12	32	2	29			49
7-12	32	2	29			49
3-7	11	7	39			43
12+	26	1	25			38
12+	25	1	26			38
7-12	17	3	31			37
12+	14	1	26			27
3-7	0	5	34			25
3-7	0	5	34			25
7-12	0	2	30			18

EXHIBIT V-4

NET COST OF EPA'S REGULATIONS

"C" Type Refineries

Capacity Range Thousand Barrels Per Day	Cents Per Barrel Crude Oil Processed					
	EPA Costs					
	Water	Airborne	Lead	Crude Price	EPA Revenue	Net EPA Cost Increase
3-7*	43	10	44	11	(36)	72
3-7	45	16	35			71
3-7	38	14	34			61
7-12*	41	6	38			60
7-12	39	8	28			50
7-12	35	5	29			44
3-7	20	10	35			40
12+	35	5	25			40
12+	31	6	26			38
12+	24	7	27			33
7-12	21	8	28			32
3-7*	0	10	44			29
12+	17	8	27			27
12+	23	4	25			27
3-7*	0	9	43			27
3-7	0	16	35			26
12+	14	6	26			21
7-12	10	8	27			20
12+	14	5	25			19
12+*	0	4	34			13
12+*	0	3	31			9
12+	0	5	25			5

*These are thermal cracking refineries. So lead cost from Exhibit C-9 was increased by 25 percent, and airborne costs reflect the no-catalytic cracking costs in Exhibit C-7.

base version of the model expansion and for the four prototype small refinery configurations. The product prices required to justify construction of the base version of the model expansion ("base expansion" hereafter) are shown in Section B.1. of Chapter III. Because their product qualities are identical, small refineries will receive the same prices[1].

In the same Section average product price less crude oil cost is estimated to be 2.5 dollars per barrel. This value is the sum of two cost elements - return on investment and cash operating cost.

New refinery capacity will be built only if investors are confident of earning 12 percent return on refinery investments[2]. This return requires an annual cash flow over the life of the plant of 21.8 percent of investment[3]. The investment cost for the base expansion is about 2,500 dollars per daily barrel of stream day capacity[4]. So annual cash flow must be (2,500 x 0.218 =) 545 dollars per daily barrel of stream day capacity. One daily barrel of stream day capacity will process (365 x 0.9 x 0.9 =) 296 barrels per year of crude oil. So unit cash flow must be (545/296 =) 1.84 dollars per barrel crude oil processed in the base expansion.

Because these plants are so much simpler than the base expansion, unit operating costs for "T", "A" and "R"-type small refineries are probably lower than those of the base expansion.

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1) The price for naphtha jet fuel, which is not made in the base expansion, is two cents per gallon below distillate fuel oil, reflecting its lower heating value.

2) Gerald A. Pogue, Estimation of the Cost of Capital for Major U.S. Industries, November, 1975 (EPA-230/3-76-001).

3) Part Two, page II-2.

4) Turner, Mason & Solomon, private communication, July 18, 1975.

Operating costs for "C"-type plants are perhaps slightly higher. But, as the analysis of refinery viability in Part One suggested, on the whole small plants are no less viable than larger plants. Consequently, one must assume that the rate of return earned by their owners is comparable to large plants and, therefore, that any operating cost disadvantage must be compensated for by other factors. One example is transportation advantage. The majority of small plants are located in relatively isolated areas. This gives them a product transportation advantage relative to their larger competitors who must ship products from more distant supply sources. Various Government programs have also advantaged small plants to some degree. Further, many small plants are located near indigenous crude oil supplies, so their crude oil acquisition costs are advantageous. It will be assumed that the net of these advantages and disadvantages is a ten cent per barrel higher cost for "C"-Type small refineries. As will be seen, this is not an important assumption.

Prototypes "T", "R" and "C" are premised to process low-sulfur crude oil. It was discussed earlier in this chapter that the differential price between low-sulfur and high-sulfur grades of crude oil would increase in response to environmental regulations promulgated in Europe and in Japan. The discussion also justified the reasoning that the differential increase was not an EPA cost. However, it clearly is an additional cost that must be faced by users of low-sulfur crude oil relative to base expansion costs. The low-sulfur crude oil price increase to be developed here is the increase commensurate with the manufacture of 1.2 percent sulfur residual fuel oil and 0.5 percent sulfur (European quality) distillate fuel oil. That is, the price premium for a low-sulfur crude oil from which 1.2/0.5 percent sulfur residual/distillate fuel oil can be made without desulfurization will be equal to the cost of desulfurizing residual and distillate fuel oil from high-sulfur crude oil. The data in Tables V-7, V-9 and Attachment Two of Part Two are useful for this derivation. The cost to manufacture 1.2 percent sulfur residual fuel oil from Arabian light crude oil in large refineries is about 1.6 dollars per barrel residual fuel oil. Residual fuel oil yield in Europe is about 40 percent volume of crude oil fed¹⁾. Therefore, low sulfur crude oil price differential should increase by (160 x 0.40 =) 64 cents per barrel crude oil because residual fuel oil desulfurization is obviated. Similarly, the price should increase by (90 x .276 x .35²⁾ =) 9 cents per barrel due to obviating distillate fuel oil desulfurization. Additionally, low-sulfur crude oil has historically received a 10 cent per barrel premium to reflect the less demanding metallurgy required in processing equipment.

One further crude oil price adjustment is necessary. The prototype refinery yield structures for "T", "R", and "C"-type refineries were based on a 40 degree API domestic low-sulfur crude oil. The (high-sulfur) crude oil assumed to be used in the model expansion is 35 degrees API. Consequently it is necessary to increase crude oil cost by 10 cents per barrel in addition to the 83 cents per barrel already assigned to reflect sulfur content³⁾.

"A"-type small refineries will purchase high sulfur crude oil similar to that used in the base expansion. So there will be no sulfur adjustments to crude oil prices. However, "A" plants will purchase heavier crude oils (25 versus 35 degrees API). So their crude oil cost will be (10 degrees x 2 cents per degree =) 20 cents per barrel less than experienced by the base expansion.

It seems likely that, by 1983, natural gas supply to small refineries will be sharply curtailed and/or its price will increase markedly. This development will reduce small refineries' cash flow. The small refinery yields shown in Section B. above are premised on self-sufficiency. That is, no outside energy is purchased except for electricity. In this way the cost of natural

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1) 44.7 percent long residue (Table V-7) less 5 percent catalytically cracked, (Oil and Gas Journal, December 29, 1975).

2) Only about one-third of distillate need be desulfurized to 0.1 percent sulfur for the entire stream to average 0.5 percent.

3) Assumes 2 cents per barrel per degree API, the longstanding U.S. differential.

gas replacement was implicitly included in the yields. So no additional cost need be assigned.

Cash flow estimates for the small refinery prototypes can now be computed:

Estimated Cash Income Before Tax For Small Refinery Prototypes
In 1983 In The Absence Of EPA's Regulations
(1974 dollars per barrel crude oil processed)

	Refinery Configuration			
	"T"	"R"	"C"	"A"
Base Expansion Cash Flow	1.84	1.84	1.84	1.84
Adjustments Relative to Base Expansion				
Product Revenue	0.22	0.43	0.66	(0.73)
Operating Cost	0.15	0.05	(0.10)	0.05
Crude Oil Cost -				
Sulfur	(0.73)	(0.73)	(0.73)	-
Metallurgy	(0.10)	(0.10)	(0.10)	-
Gravity	(0.10)	(0.10)	(0.10)	0.20
Small Refinery Cash Flow[1)]	1.28	1.39	1.47	1.36

D. Impact of EPA's Regulations on Small Refineries

The impact of EPA's regulations on small refineries can now be determined by comparing these cash flow estimates to the net EPA costs shown in Exhibits V-1 through V-4. The

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1) These estimates are much higher than historical cash earnings of small refineries. The reason is the high cash flow needed by the base expansion. This reflects the high cost of refinery expansion - see discussion in the last paragraph of Chapter IV, Section D.

impacts are plotted in Exhibits V-5 and V-6. These Exhibits show that no refineries will be forced to close because of EPA's regulations. This statement, of course, is an oversimplification for it ignores cases of physical infeasibility or extraordinary costs. Undoubtedly some of these exist. Nevertheless the protection afforded existing refineries by the inflation of refinery construction costs from 1970 to 1975 is more than sufficient to shield all but special-case refineries from serious harm by EPA's regulations.

None of the small refineries' cash income before tax is reduced by more than one-half by EPA's regulations. And the cash flow of the most affected plant is still about 70 cents per barrel of crude oil processed. If this refinery were to have an expected remaining life of 20 years, its capital value would be nearly one thousand dollars per daily barrel of stream day capacity1).

E. Estimated Small Refinery Closures

It was concluded that the additional costs and investments attributable to EPA's regulations are, of themselves, insufficient to cause the closure of any of the existing small plants in the capacity range of 20 thousand barrels per day or less. It is, however, likely that the inevitable closures of certain of the older plants that are approaching the end of their normal economic life will be accelerated. Similarly the closure of plants whose viability is adversely affected by changes in crude oil supplies or customer requirements may also be accelerated. And it may be physically infeasible to install effluent control equipment in some plants.

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1) $\frac{.70 \times 365 \times .9 \times .9}{.218}$ = 950 dollars per barrel

EXHIBIT V-5

SMALL REFINERY CASH INCOME BEFORE TAX AFTER IMPACT OF EPA'S REGULATIONS

"T" and "R"-Type Refineries

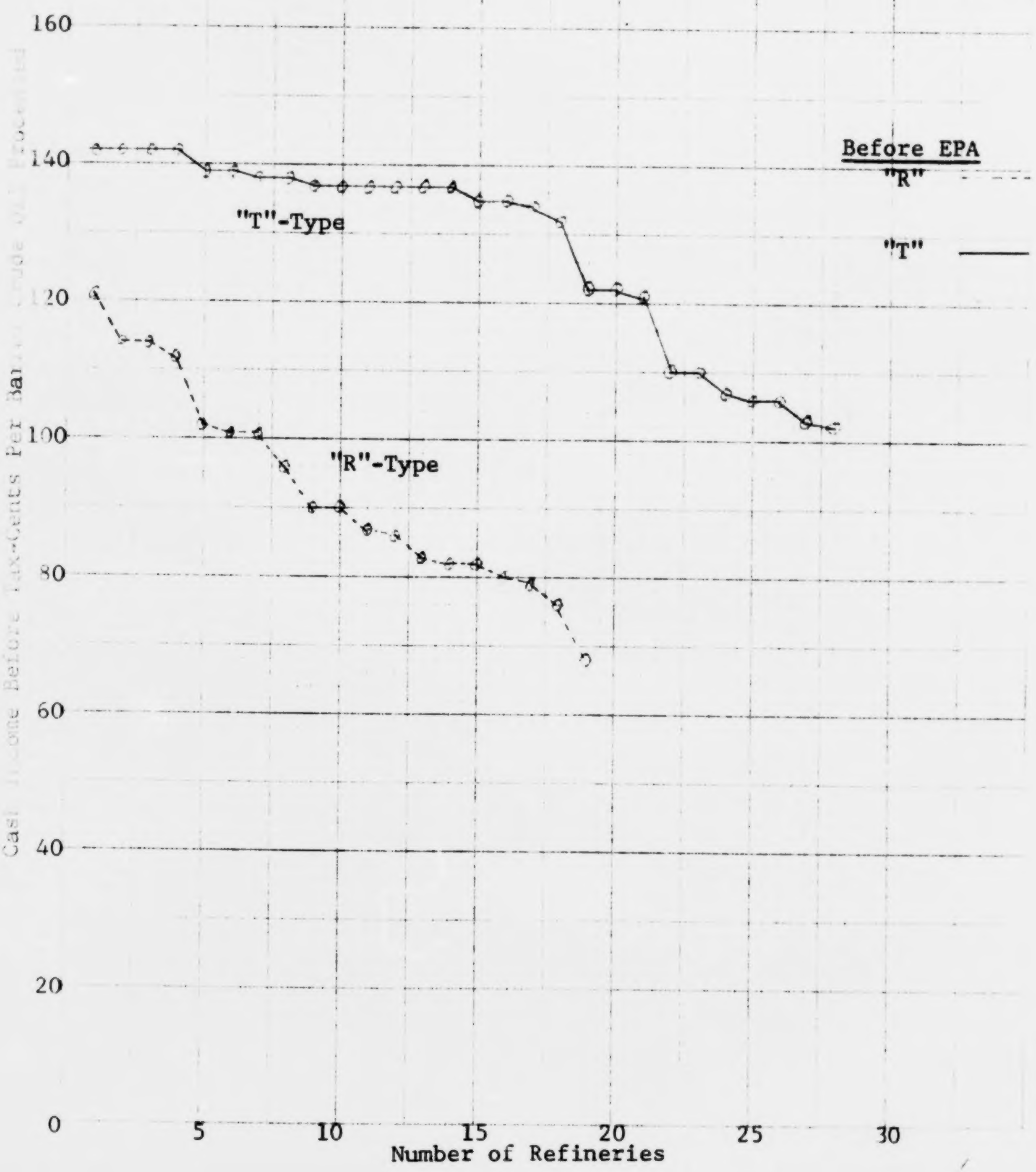
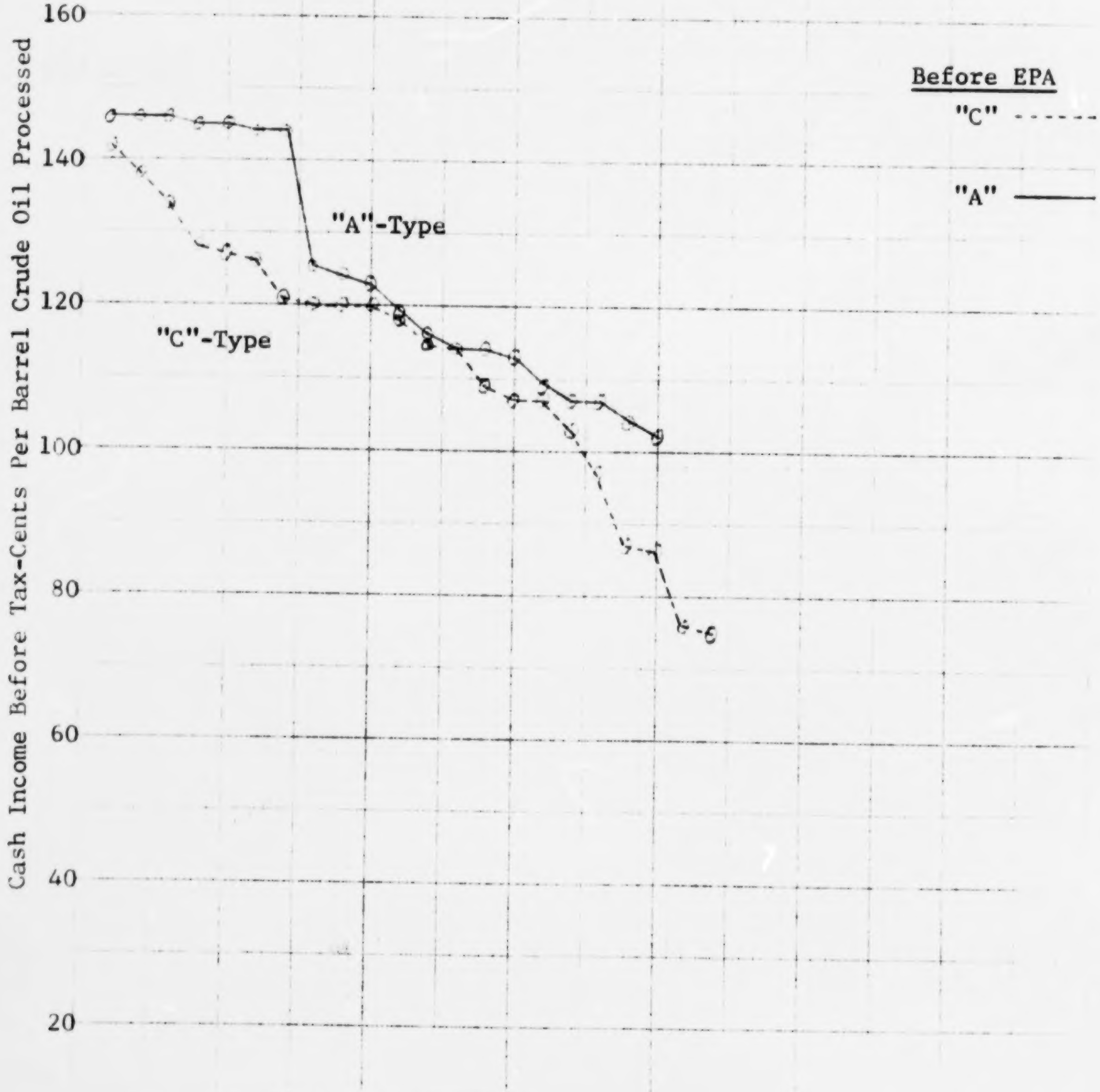


EXHIBIT V-6

SMALL REFINERY CASH INCOME BEFORE TAX AFTER IMPACT OF EPA'S REGULATIONS

"C" d "A"-Type Refineries



F. Employment Effects

The 100 small refineries in the continental U.S. of 20 thousand barrels per day capacity or less have an aggregate capacity of approximately 800 thousand barrels per day and employ about 7,000 persons. Thus, while the number of plants amounts to around 40 percent of the industry's total, capacity and employment for this group of refineries represents only about five percent of the industry's total in each of these categories.

Over one-half of the total number of plants (and employees) are located in towns of less than 5,000 population. One-half of these are located in towns of less than 1,000 population.

Since no plants are expected to close solely because of the impact of EPA's regulations, the employment effect of these regulations is to increase employment by a small amount.

CHAPTER VI

SENSITIVITY ANALYSES

The purpose of this Chapter is to determine the sensitivity of conclusions reached in this work to different values of key determinants of the effects of EPA's regulations. Specifically, five areas will be addressed. The effects on EPA impact of different values for the following determinants will be derived:

1. Capital cost of facilities required by EPA's regulations;
2. U.S. tariff protection;
3. Differential between high-sulfur and low-sulfur crude oil prices;
4. Demand elasticity estimates;
5. Crude oil prices.

The methodology to be used in each analysis is to repeat what has been done before. In the case of capital costs, high-sulfur versus low-sulfur price differential, and elasticity estimates the analysis is straightforward. The case of lower tariff protection is quite different from the base analysis because no new refinery capacity will be installed (except that which is now planned). The analysis of different crude oil prices will, as specified in the Work Statement for this contract, be performed in a qualitative manner. That is, the direction and relative magnitude of the effects will be derived, but specific numerical estimates will not be prepared.

A. Effect of Higher, or Lower, Capital Costs for EPA Investments

Higher unit capital costs for conforming new refinery capacity to EPA regulations will cause higher per-barrel annual compliance costs, and (identically) higher EPA-caused price increases. The value of P_2 will increase in the equation for the demand curve:

$$\left\{\frac{Q_2 - Q_1}{Q_1}\right\} = \left\{\frac{P_2}{P_1}\right\}^e - 1$$

Since elasticity is negative, Q_2 will be smaller, that is, less product will be demanded by consumers. So less new refinery capacity will be needed.

For existing-in-1973 refineries the cost to conform to EPA's regulations will also increase. But so will cost recovery (EPA price increase times product volume).

The necessary computations are laborious. Each cost element (in Part Two) requires recalculation to reflect different capital costs and, consequently, different annual costs. And all the analyses in Chapters II, III, and IV must be redone. Nevertheless, the work is straightforward.

Results of the analysis are presented in two Exhibits. Exhibit VI-1 shows aggregate industry annual costs for each principal segment of EPA concern (water, airborne, etc.) for each of three levels of capital costs. Exhibit VI-2 shows the sensitivity of the EPA impact analysis to capital cost estimates. There are no unusual effects. That is, total costs increase (decrease) as anticipated. Percentage recovery of EPA costs by existing-in-1973 refineries is lower for higher capital costs. This is because annual costs of these plants are almost exactly proportional to capital costs (operating costs are net nearly zero). But product price increases are proportional to the annual costs of expansions. And these increase less than proportionately with capital cost (because operating costs are net positive).

Detailed computations of changes in the impact on all small refineries were not performed. This is justifiable because several of the most severely impacted plants were specifically checked and the maximum cost change observed was 15 cents per barrel crude oil. This means that there will be negligible change in the number of small refineries advantaged/disadvantaged by EPA's regulations. In other words, varying EPA capital estimates plus or minus 25 percent has no significant effect on the viability of the small refineries studied.

EXHIBIT VI-1

Sensitivity Analysis - EPA Capital Costs Aggregate Industry Annual Costs in 1983

(Million Dollars)

	Cost Element	Base[1] Pre-'74 Refineries	Base[1] Post-'73 Refineries[2]	EPA Capital +25% Pre-'74	EPA Capital +25% Post-'73	EPA Capital -25% Pre-'74	EPA Capital -25% Post-'73
Water	(Capital	649	151	811	185	487	115
	(Crude Oil	56	24	56	24	56	24
	(Other	129	55	129	54	129	56
	Total	834	230	996	263	672	195
Air-borne	(Capital	189	76	243	93	142	58
	(Crude Oil	35	32	30	32	38	32
	(Other	(24)	4	(24)	4	(24)	4
	Total	200	112	249	129	156	94
Product Sulfur	(Capital	47	68	69	84	36	52
	(Crude Oil	22	36	22	35	22	37
	(Other	4	7	4	7	4	7
	Total	73	111	95	126	62	96
Lead	(Capital	555	47	694	58	416	36
	(Crude Oil	173	41	173	40	173	42
	(Other	(425)	(88)	(425)	(86)	(425)	(89)
	Total	303	-	442	12	164	(11)
Total	(Capital	1,440	342	1,817	420	1,081	261
	(Crude Oil	286	133	281	131	289	135
	(Other	(316)	(22)	(316)	(21)	(316)	(22)
	Total	1,410	453	1,782	530	1,054	374

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1) From Chapter IV.

2) Capacity for Post-1973 refineries:
Base - 3,659 thousand barrels per stream day
+25% - 3,595 thousand barrels per stream day
-25% - 3,718 thousand barrels per stream day

EXHIBIT VI-2

SENSITIVITY TO DIFFERENT CAPITAL COST ESTIMATES

	Capital Cost of EPA-Required Facilities		
	Base	Base +25%	Base -25%
Product Price Increases Associated With EPA's Regulations - cents per gallon			
Gasoline	1.0[1]	1.2	.8
Kerosene Jet Fuel	1.0	1.2	.9
Distillate Fuel Oil	1.1	1.2	.9
Residual Fuel Oil	1.1	1.3	.9
Asphalt	1.0	1.1	.8
All Other Products	1.1	1.2	.9
Revenue Increase to Pre-'74 Refineries-billion dollars per year	2.0[2]	2.3	1.6
Consumption Changes Associated With Price Increases-million barrels per day			
Gasoline	+.051[3]	+.029	+.065
Kerosene Jet Fuel	-.004	-.006	-.004
Distillate Fuel Oil	-.057	-.061	-.045
Residual Fuel Oil	-.077	-.093	-.065
Asphalt	-.002	-.003	-.002
All Other Products	-.034	-.037	-.028
Total	-.123	-.171	-.079
Equivalent Refinery Capacity million barrels per stream day	-.165[4]	-.229	-.106
(Net) Cost of Conforming to EPA's Regulations - million dollars			
Capital Investment, 1974-1983			
Pre-'74 Capacity	4,804[5]	6,022	3,596
Post-'73 Capacity	1,139	1.399	868
Annual Cost in 1983			
Pre-'74 Capacity	1,410[6]	1,782	1,054
Post-'73 Capacity	453	530	374
Percent of Annual EPA Cost in Pre-1974 Refineries Recovered Via Higher Prices	140[7]	130	150

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1) Chapter II, Section C.
2) Chapter IV, Section D.
3) Chapter III, Section C.7.
4) 0.123/(0.92 x 0.9 x 0.9)
5) Chapter IV, Section C.4.
6) Exhibit VI-1.
7) Revenue increase/annual cost = 2.0/1.41 = 142 percent

B. Effect of a Lower Level of Tariff Protection

It was developed in Section D.2. of Chapter II that a high tariff on imported petroleum products might be required to protect new U.S. refinery capacity expansion from predatory behavior by OPEC countries. So a high tariff was taken as a principle premise underlying this study. It is instructive to derive the impact on EPA costs of a lower level of tariff protection.

The major effect of a lower level of tariff protection would be that no new refinery capacity would be constructed that is not now firmly planned. (Even those plants on the "firm" list that have not yet commenced construction might also not be built, but such will be assumed to not be the case.) Moreover, because new plants will not be built, the price increase necessary to justify EPA costs in such plants will not be forthcoming.

Several levels of tariff protection might develop. For example, there might be no protection at all. The logical outcome of such a situation would be to reduce the capacity of the U.S. refining industry to the level needed to process U.S. crude oil production. And U.S. crude oil prices would fall to the level necessary to support that size for the refining industry. In other words, the U.S. crude oil industry would find it necessary to create the "tariff" necessary to protect its market. This is not a useful case for analysis here, for it would reduce the existing U.S. refining industry by one-third or more.

Another reasonable tariff level to analyze would be 84 cents per barrel, which is the maximum protection available under current law. Here again, the level is not nearly high enough to protect against predatory OPEC actions and the same result discussed in the preceding paragraph might occur.

It appears that an interesting and useful analysis would be to assume a tariff level (or combination of tariff and crude oil price subsidy) sufficiently high to encourage construction of the base version of the model expansion defined in

Chapter II, but not high enough to support the EPA version. That is, it would be about 39 cents per barrel below the level needed to protect the EPA version1). This level of tariff is interesting because it would eliminate new refinery construction without leading to abandonments of existing-in-1973 plants. However, it would lead to substantial reductions in cash income before tax of these refineries.

This level of tariff protection would mean that EPA's regulations would have no effect on prices in the U.S. market (because prices would be set by imported products not subject to EPA's regulations). So there would be no recovery of EPA costs. And there would be no volume effects of EPA's regulations. Thus the effects to be evaluated are impacts on existing-in-1973 refineries, with particular emphasis on small refineries.

Over-all industry impacts at this lower level of tariff protection would be as follows:

	Level of Tariff Protection	
	Base	Lower
Costs of Conforming to EPA's Regulations in Existing-in-1973 Refineries - million dollars2)		
Cumulative Capital - 1974/1983	--- 4,800 ---	
Annual in 1983	--- 1,410 ---	
Percent Change in 1983 Cash Income Before Tax for these Refineries Due to EPA Annual Cost3)	+8	-20

---

1) Chapter II, Section B.4.

2) Chapter IV, Section C.4.

3) Cash income before tax (cash flow) in the absence of EPA's regulations would be about 1.4 dollars per barrel crude oil processed (Chapter V, Section C.) With base level tariff, cash flow increases by 11 cents per barrel due to EPA's regulations (Chapter IV, Section D.). With the lower level of tariff protection the entire EPA cost of (1.41 billion dollars per year/5.0 billion barrels per year =) 28 cents per barrel would have to be absorbed.

Although average impairment of cash income before tax is substantial it is not so large as to force abandonment of any known plants.

The impact on small refineries of a 39 cent per barrel lower petroleum product import tariff in Chapter V would be about the same as the impact on the over-all industry. Exhibits V-5 and V-6 in Chapter V show that, given the base level of tariff protection, all the small refineries studied would remain financially sound after paying for EPA's regulations. But at the lower level of tariff they would not receive any EPA revenue. This would reduce their cash income before tax by 39 cents per barrel crude oil processed.

Impacts on the one specific individual refinery within each type which would be most affected by a lower tariff are as follows:

	Refinery Configuration			
	"T"	"A"	"R"	"C"
Cash Income Before Tax With EPA's Regulations-Cents Per Barrel Crude Oil Processed				
High Tariff (base)[1]	102	102	68	75
Low Tariff[2]	63	63	29	36

The impacts of a lower tariff are substantial. However, the remaining before tax cash flows of 29-63 cents per barrel are certainly adequate to insure the continued viability of these plants.

The top line in the foregoing table indicates that tariff levels more than about 65 cents below the premised base level would

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1) Chapter V, Exhibits V-5 and V-6.

2) High tariff cash flow less 39 cents per barrel due to tariff reduction.

cause refinery shutdowns (or force domestic crude oil price concessions). Each incremental additional reduction in tariff level would, of course, further exacerbate the impact.

C. Effect of a Lower Price Differential Between High-Sulfur and Low-Sulfur Crude Oils

There are at least six possible developments which could result in a lower price differential to U.S. refineries:

1. The discovery of prodigious reserves of low-sulfur crude oils which can be rapidly developed.
2. Abandonment or major relaxation of sulfur oxide emission regulations in Europe and Japan.
3. A major breakthrough in refinery technology such that the costs for desulfurizing residual fuel oil are substantially reduced.
4. A very large increase in international sulfur prices.
5. An OPEC decision to utilize rationing instead of price to balance the supply and demand of low-sulfur crude oils.
6. A U.S. Government decision to subsidize the price of low-sulfur crude oils relative to high-sulfur.

Each of these events is considered to be improbable. Even in aggregate it is unlikely that the low-/high-sulfur crude oil price differential could be significantly affected over the 1974/1983 time period considered. Nevertheless, it was instructive to develop the effects of a large reduction in differential.

The differential chosen for evaluation was zero, that is, the price of crude oil was assumed to be independent of sulfur content. This also means that EPA's sulfur regulations would be costless1). Although such a situation could not occur in practice, it is convenient to evaluate. The relationship between sulfur control cost and crude oil price differential is essentially linear. So the cost of intermediate levels of the differential can be simply approximated by proportion.

A high price differential between low-sulfur and high-sulfur crude oils was used in the small refinery impact analysis (Chapter V, Section C.). There it was derived that a crude oil from which a 40 percent volume yield of 1.2 percent sulfur residual fuel oil could be manufactured was 83 cents per barrel more valuable than light Arabian crude oil. The sulfur content of light Arabian crude oil is 1.65 percent2). The sulfur content of the premised low-sulfur crude oil is about 0.69 percent3). So the unit sulfur differential is:

$$\frac{83}{(1.65 - 0.69)} = 86 \text{ cents per barrel per percent sulfur}$$

In order to develop the zero differential case it was necessary to recompute all the data shown in Chapters II, III and IV that are affected by sulfur regulations. Revised aggregate industry annual costs are shown in Exhibit VI-3. Impacts of the high differential and zero differential are compared in Exhibit VI-4. As expected, the cost effects are large. And existing-in-1973 refineries are shown to be relatively advantaged by EPA's sulfur regulations. This is because percent yield of residual fuel oil, and use of liquid refinery fuel in these plants are lower than those of the model.

For small refineries it was necessary to recompute the data presented in Chapter V. The effects of differential on the one specific refinery within each type that was most heavily impacted by EPA's regulations are shown in the following table:

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1) Because every refinery would purchase a grade of crude oil such that no facilities for sulfur control would be needed.

2) Part Two, Table V-7.

3) For light Arabian: $\frac{\text{crude oil sulfur}}{\text{residual sulfur}} = \frac{1.65}{2.89} - 0.57$. Thus, the low-sulfur crude oil is 0.57 x 1.2 = 0.69 percent sulfur.

4) Chapter V, Exhibits V-5 and V-6.

EXHIBIT VI-3

Sensitivity Analysis
Price Differential Between High-Sulfur and Low-Sulfur Crude Oils
Aggregate Industry Annual Costs in 1983

(Million Dollars)

		Base[1]		Zero Price Differential	
	Cost Element	Pre-'74 Refineries	Post-'73 Refineries[2]	Pre-'74	Post-'73
Water	(Capital	649	151	649	157
	(Crude Oil	56	24	56	25
	(Other	129	55	129	57
	Total	834	230	834	239
Airborne	(Capital	189	76	63	2
	(Crude Oil	35	32	(9)	-
	(Other	(24)	4	2	-
	Total	200	112	56	2
Product Sulfur	(Capital	47	68	-	-
	(Crude Oil	22	36	-	-
	(Other	4	7	-	-
	Total	73	111	-	-
Lead	(Capital	555	47	555	49
	(Crude Oil	173	41	173	43
	(Other	(425)	(88)	(425)	(92)
	Total	303	-	303	-
Total	(Capital	1,440	342	1,267	208
	(Crude Oil	286	133	220	68
	(Other	(316)	(22)	(294)	(35)
	Total	1,410	453	1,193	241

---

1) From Chapter IV. Price differential is 86 cents per barrel per per percent sulfur in crude oil.

2) Capacity for post-1973 refineries:
Base - 3,659 thousand barrels per stream day
Zero Price Differential - 3,816 thousand barrels per stream day

EXHIBIT VI-4

Sensitivity to Price Differential Between High-Sulfur and Low-Sulfur Crude Oils

	Price Differential	
	Base 1)	Zero
Product Price Increases Associated With EPA's Regulations -cents per gallon		
Gasoline	1.0	.5
Kerosene Jet Fuel	1.0	.6
Distillate Fuel Oil	1.1	.6
Residual Fuel Oil	1.1	.6
Asphalt	1.0	.7
All Other Products	1.1	.6
Revenue Increase to Pre-'74 Refineries-billion dollars per year	2.0	1.2
Consumption Changes Associated With Price Increases - million barrels per day		
Gasoline	+.051	+.091
Kerosene Jet Fuel	-.004	-.003
Distillate Fuel Oil	-.057	-.031
Residual Fuel Oil	-.077	-.043
Asphalt	-.002	-.001
All Other Products	-.034	-.019
Total	-.123	-.006
Equivalent Refinery Capacity million barrels per stream day	-.165	-.008
(Net) Cost of Conforming to EPA's Regulations - million dollars		
Capital Investment, 1974-1983		
Pre-'74 Capacity	4,804	4,226
Post-'73 Capacity	1,139	694
Annual Cost in 1983		
Pre-'74 Capacity	1,410	1,193
Post-'73 Capacity	453	241
Percent of Annual EPA Cost in Pre-1974 Refineries Recovered Via Higher Prices	140	100

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1) Price differential is 86 cents per barrel per percent sulfur in crude oil.

	Refinery Configuration			
	"T"	"A"	"R"	"C"
Cash Income Before Tax With EPA's Regulations-Cents Per Barrel Crude Oil Processed				
High Differential(base)	102	102	68	75
Zero Differential	108	116	76	76
Percent Decrease in Cash Income Before Tax Due to EPA's Regulations				
High Differential(base)	20	25	51	49
Zero Differential	16	15	45	48

The impact of EPA's regulations on these plants is only slightly affected by sulfur content price differential.

D. Effect of Different Elasticity Estimates

The per-barrel costs of EPA's regulations (in both existing and new facilities) are independent of elasticity. So EPA price changes are unaffected by different elasticity estimates. Given these two facts it follows that capital costs, annual costs, and cost recovery for existing-in-1973 refineries are unaffected. And the impacts on small refineries are also unaffected.

Different elasticity estimates do have effects on the total EPA costs of new refinery capacity. This reflects the dependence of Q_2 in the demand equation on elasticity. These effects are computed for two cases:

1. More elastic demand response to price. Each elasticity estimate was made (absolutely) larger by adding -0.25 to the values presented in Chapter III.

2. Less elastic response. Since the elasticity estimates for jet fuel and asphalt in Chapter III are already low (-0.13 and -0.12) these were not changed. Each of the other estimates was (absolutely)decreased by subtracting -0.25 from the Chapter III values.

Results of the computations are shown in Exhibit VI-5. Relative to the original case presented in Chapters III and IV, the effects of a more elastic demand response are to decrease product consumption by 240 thousand barrels per day, decrease the investment requirement for growth by about 0.8 billion dollars[1], and decrease investment required to meet EPA's regulations in capacity expansions by 0.1 billion dollars. The effects of a less elastic demand response are similar, but in the opposite direction, i.e., increased product consumption and investments instead of decreased.

E. Effect of Lower or Higher Crude Oil Prices

Sensitivity of the impact analysis to higher or lower crude oil prices was also considered. Lower crude oil prices would affect the analysis in a straightforward manner. However, substantially higher crude oil prices would change the analysis fundamentally because a basic premise underlying the analysis would have to be abandoned. The effects will be developed separately.

1. Lower Crude Oil Prices

With one exception the analysis of EPA impacts at a lower crude oil price requires simply recalculating Chapters II through V with lower product prices and energy costs. The exception is the effect of crude oil price on the profitability of such control measures as reduction of hydrocarbon emissions from storage tanks. At low crude oil prices only large tanks

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1) (-0.487 -(-.165) million barrels per stream day) x 2.5 thousand dollars per daily barrel = -0.805 billion.

EXHIBIT VI-5

Sensitivity To Different Elasticity Estimates

	Elasticity Estimates		
	Base[1]	More Elastic	Less Elastic
Consumption Changes Associated With EPA Price Increases - million barrels per day			
Gasoline	+.051	-.116	+.220
Kerosene Jet Fuel	-.004	-.015	-.004
Distillate Fuel Oil	-.057	-.079	-.033
Residual Fuel Oil	-.077	-.099	-.057
Asphalt	-.002	-.008	-.002
All Other Products	-.034	-.046	-.022
Total	-.123	-.363	+.102
Equivalent Refinery Capacity million barrels per stream day	-.165	-.487	+.137
(Net) Cost of Conforming to EPA's Regulations - million dollars			
Capital Investment, 1974-1983			
Pre-'74 Capacity	- - - - -	4,804	- - - - -
Post-'73 Capacity	1,139	1,039	1,233
Annual Cost in 1983			
Pre-'74 Capacity	- - - - -	1,410	- - - - -
Post-'73 Capacity	453	413	490

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1) Base elasticity estimates are developed in Chapter III.

can be profitably controlled. So each successively lower price would reclassify an additional increment of investments from "profitable" to "EPA". Consequently, computation of EPA impacts at lower crude oil prices requires a redetermination of the "breakeven" refinery capacity (that capacity at which refiners would be indifferent to making the control investment) for each of four airborne emission control methods (see Appendix B).

A three dollar per barrel reduction of crude oil price (from the 12.75 dollars per barrel delivered to U.S. refineries utilized in Chapters II through V to 9.75 dollars per barrel) would decrease the costs of EPA's regulations in the model expansion by about two cents per barrel crude oil processed. This reduction reflects the lower value of refinery fuel utilized as energy to operate EPA facilities. The product price effect of this cost reduction would be about 0.05 cents per gallon relative to the base crude oil price.

EPA costs to existing-in-1973 refineries would be slightly increased (due to the "breakeven" change) from the levels shown in Chapter IV. Competitive impacts on existing-in-1973 small refineries would be about the same as was determined in Chapter V at the base crude oil price.

A lower crude oil price would stimulate product consumption in accordance with the demand curve - the lower the price, the higher the quantity demanded. A crude oil price of 9.75 dollars per barrel would require about twice the volume of new refinery capacity to be constructed during 1974/1983 as was needed at a 12.75 dollar price. So aggregate EPA costs for new capacity would be about twice those shown in Chapter IV.

2. Higher Crude Oil Prices

The effect of a one dollar per barrel crude oil price increase (to 13.75 dollars) would be consistent with the price decrease results, but in the opposite direction. That is, the EPA impact on existing-in-1973 refineries would be almost the same as at 12.75 dollars per barrel, but capital requirements for expansion capacity would be less.

A crude oil price increase of five dollars per barrel (to 17.75 dollars) would have a profound impact on the petroleum refining industry. The analysis in Chapters II through V rested on a product consumption forecast for 1983 consistent with a 12.75 per barrel crude oil price. At 17.75 dollars per barrel, product consumption in 1983 would be lower. So much lower, in fact, that there would not only be no need for refinery expansion, but some retirement of existing-in-1973 facilities would be needed to balance demand with supply at an economic utilization rate. In such a situation product prices would reflect the cash-out-of-pocket costs of the least efficient refiner who was needed to balance the market - all higher cost plants would close. The impact of EPA's regulations in such an economic climate would be severe. The only cost recovery that could occur would come from the cash cost increase experienced by the least efficient refiner who was able to stay in business. Marginal operating costs of EPA facilities are low. So EPA cost recovery by industry would be negligible. Hence, essentially the entire capital costs of EPA's investments would have to be absorbed by the industry (or, to a certain extent in special cases, by domestic crude oil producers).

A 15.75 dollars per barrel price (three dollar increase) would produce intermediate effects. Consumption of those products that are more price elastic, i.e., gasoline and residual fuel oil, would be lower in 1983 than in 1973. Consumption of less price elastic products would increase. The net effect would be to require additional refining capacity to manufacture distillate fuel oil, jet fuel and petrochemical feedstocks, coupled with a reduction in the output of gasoline and residual fuel oil in existing refineries. Clearly, a period of price instability would ensue until a new equilibrium was established.

It will be recalled that, at a crude oil price of 12.75 dollars per barrel, the EPA cost of manufacturing unleaded gasoline in new refineries is nil. Consequently, existing-in-1973 refineries are forced to fully absorb the cost of converting to unleaded gasoline. So, higher crude oil prices will not further disadvantage existing plants on this account.

The reduction in residual fuel oil consumption in response to high price could be accommodated by a reduction in imports rather than a reduction in domestic manufacture. In either case, the cost of controlling sulfur content of residual fuel oil and refinery liquid fuel would be only slightly increased by crude oil prices higher than 12.75 dollars per barrel crude oil.

It can be concluded that any crude oil price that leads to a net increase in petroleum product consumption over the 1973-1983 period will have about the same EPA impacts on existing-in-1973 refineries. And, of course, EPA costs for capacity expansion are proportional to the quantity of the expansion.

APPENDIX A

REFINERY EXPANSION REQUIREMENTS AND THE EPA COSTS THEREOF

In order to measure the economic impact on the U.S. refining industry of EPA's regulations, it is necessary to develop a forecast of requirements for new refinery capacity. The technical sub-contractor, Turner. Mason and Solomon, (TM&S), prepared such a forecast in their report (Part Two). Their methodology and data sources are described in pages II-4 through II-6. Table IV-4 presents the key parts of the forecast. It is reproduced on the next page (Exhibit A-1).

The purpose of this Appendix is to review and modify the forecasts in Exhibit A-1 and determine associated costs of EPA's regulations. Specifically, in this Appendix we shall:

1. Develop a revised forecast for motor gasoline demand.
2. Develop a revised forecast for refinery expansion requirements.
3. Determine down-stream processing facility needs for the model refinery expansion.
4. Determine the specific processing cost changes in the model expansion which can be attributed to EPA's regulations.

1. Revised Motor Gasoline Demand

Table A-2 in Part Two presents TM&S's domestic petroleum demand forecast. This forecast is based on a 1974 report1) by the National Petroleum Council (NPC). The NPC forecast represents a concensus of eight energy supply/demand projections by individual

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1) National Petroleum Council, Emergency Preparedness for Interruption of Petroleum Imports into the United States, September, 1974.

EXHIBIT A- 1

TABLE IV-4

FORECAST OF ADDITIONAL CAPACITY

INSTALLATIONS AND PRODUCTS PRODUCTION

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
Refinery, MB/SD	684	573	1,422	516	722	212	212	212	212	212
Catalytic Cracking, MB/SD	212	178	441	160	224	66	66	66	66	66
Sulfur Plant, LT/SD	1,310	1,097	2,723	988	1,383	406	406	406	406	406
Gasoline, MB/CD	244	244	244	245	200	200	98	98	98	98
Naphtha Jet Fuel, MB/CD	0	0	0	0	0	0	0	0	0	0

members of the industry. The projections were based on an assumption that "real" unit prices for energy raw materials would remain at mid-1974 levels.

We feel that the NPC has overestimated future gasoline consumption. Although it is not stated what specific price elasticities of demand for motor gasoline were used by the individual participants in the study, page 34 in the report presents a range of estimates which average -0.21. This level is consistent with those recommended by the NPC in earlier studies. In contrast, the Project Independence Report1) used a long-term elasticity of demand of -0.76 for motor gasoline (mix of passenger cars plus commercial). And internal studies by Sobotka & Company, Inc., have confirmed elasticity levels to be of about this magnitude. Accordingly, we shall modify the NPC-based estimate for 1985 motor gasoline demand to reflect the -0.76 elasticity2).

The new gasoline demand estimate will utilize data from two earlier NPC reports - a 1972 report3), and a 1973 report4). Page 37 of the 1972 report shows a projected transportation energy demand in 1985 (intermediate case) of 28.3×10^{15} BTU. (It was assumed that unleaded gasoline of 91-93 research octane will supply post-1976 vehicles.) Page 51 of the 1973 report indicates that 51 percent of total transportation energy consumption is met by passenger car gasoline and 13 percent by commercial gasoline.

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1) Federal Energy Administration, Project Independence Report, November, 1974.

2) It may be argued that the time period 1974-1985 is not "long", so that a lower elasticity estimate should be utilized. However, only about 1/10 of cars and 1/4 of trucks on the road are older than ten years. Hence, approximately 85 percent of fuel consumption in 1985 will be in vehicles purchased with knowledge of high fuel prices.

3) National Petroleum Council, U.S. Energy Outlook - A Report of the National Petroleum Council's Committee on U.S. Energy Outlook, December, 1972.

4) National Petroleum Council, U.S. Energy Outlook - Energy Demand, 1973.

The 1985 gasoline consumption forecast can be computed from these data. It is:

$$\frac{28.3 \times 10^{15} \times 0.64}{365 \times 5{,}248{,}000^{1)}} = 9.46 \text{ million barrels per day}$$

The 1972 report assumed that then-current crude oil prices (about $3.75 per barrel) would prevail indefinitely in "real" terms. So the demand just computed would apply if gasoline retail prices had remained in parity with a $3.75 per barrel crude cost in 1972.

By 1973 the average price of crude oil had inflated to about $4.00 per barrel. We shall assume that the average retail price for motor gasoline (premium and regular mix including consumer tax)in parity with this $4.00 per barrel average crude price is 40 cents per gallon. This assumption rests on the following evidence.

a) The Project Independence Report assumed that an average $4.00 per barrel crude price and 39.71 cents per gallon retail gasoline price existed in 1973.

b) The Basic Petroleum Data Book published by the API in October, 1975, reports for 1973 that the average wellhead price for U.S. crudes was $3.89 per barrel and the average retail price for regular gasoline was 38.92 cents per gallon.

We shall also assume that the U.S. refining industry produced on average approximately 95 percent volume of salable liquid products from crude oil in 1973. (The 5 percent disappearance is the net of three percent processing gain minus eight percent refinery fuel consumption.) Therefore, we can calculate the crude oil cost component (raw material plus fuel) of the gasoline price in 1973 to have been:

$$\frac{4.00 \times 100}{.95 \times 42} = 10 \text{ cents per gallon}$$

---

1) Average BTU per barrel for motor gasoline.

Since the parity gasoline retail price was forty cents per gallon, we can calculate by difference the sum of all other cost elements (refining, distribution and marketing costs; taxes, profit margins, etc.) to be thirty cents per gallon in 1973. These other cost elements will not be appreciably affected by changes in crude oil prices. Further, we shall assume that these will not change when measured in 1973 dollars, except for an additional one cent per gallon refinery margin due to recent capital inflation.

We now have all the elements needed for a 1985 gasoline consumption forecast except the 1985 crude oil price. The Federal Energy Administration reported1) that imported crude oil delivered costs (excluding import tariffs) averaged about $12.75 per barrel for the eighteen month period beginning March, 1974. There is no defensible way to forecast how this price will change between now and 1985. So we will assume without justification that it will not change in constant dollars.

The inflation-adjusted price consistent with a $4.00 per barrel price in 1973 is derived as follows:

1. The average GNP price deflator for 1973 was 154.3
2. The average GNP price deflator for the period March, 1974-August, 1975 was about 180.
3. Hence, the price in "1973 dollars" of imported crude oil was:

$$12.75 \times \frac{154.3}{180} = \$10.93 \text{ per barrel}$$

The "parity" retail gasoline price consistent with $10.93 per barrel marginal crude oil cost is:

Crude Price - dollars per barrel	4.00	10.93
Crude Cost Component - cents per gallon	10	27
Other Costs - cents per gallon	31	31
Gasoline Retail Price - cents per gallon	41	58

---

1) FEA, Monthly Energy Review, November 1975, p.53.

The revised 1985 motor gasoline consumption forecast can now be computed:

$$Q_2 = Q_1 \left(\frac{P_2}{P_1}\right)^e$$

$$Q_2 = (9.46 \text{ million}) \left(\frac{58}{41}\right)^{-0.76}$$

$$= 7.27 \text{ million barrels per day}^{1)}$$

(This contrasts with the forecast in Table A-2 of the Part Two Appendix of 8.414 million barrels per day. The difference is 1.144 million barrels per day.)

2. Revised Total Product Demands and New Refinery Capacity Requirements

The 1974 NPC forecast of 1985 oil product demands, reduced by 1.1 million barrels per day to reflect our new gasoline forecast, is compared below with demands estimated in Project Independence:

1985 Demand for Petroleum Products
(Million Barrels Per Day)

1974 NPC		Project Independence	
Original 2)	Revised 3)	$7 Crude	$11 Crude
21.8	20.7	23.7	19.1

Since the total demand shown for the "Revised" NPC forecast falls within the range of the PI cases, we shall make no further adjustments to product demands.

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1) The precision implied by reporting more than two significant figures is spurious. We do it for consistency with historical data.

2) Part Two, Table A-2.

3) Reduced by 1.1 million barrels per day.

In Table A-3 of Part Two is shown the quantity demanded from domestic refineries of the various petroleum products during 1985. These values were derived by the technical sub-contractor by subtracting net imports and other sources of supply from the NPC gross product demand forecast. These will be the primary data source for our revised estimate of new refinery capacity requirements. Gasoline (automotive and aviation) demanded from domestic refineries in 1985, which is shown as 8,276 thousand barrels per calendar day in Table A-3, was reduced by 1,144 as derived in the previous section.

The methodology for estimating new refinery requirements is to subtract the outturn from existing (as of the first of 1974) refinery capacity operating at 90 percent utilization from (adjusted) 1985 demands shown in Table A-3 of Part Two. The results of this analysis are displayed in Exhibit A-2. There are shown 1985 demands on domestic refineries and the outturn from processing 12,825 thousand barrels of crude oil per day (90 percent utilization) in 1985 in refinery capacity which existed as of 1/1/74. Required outturn from new capacity is derived by difference. Later on in this section it will be shown that refinery configurations of the type which will typify expansions will produce 92.7 percent volume yield of liquid products. Hence, the crude oil required to be processed in expansion capacity is $\frac{3,033}{0.927}$ = 3,272 thousand barrels per day.

It should be noted that this rate of required crude runs must be maintained on average for each of the 365 days in the calendar year. Therefore, to determine total new processing capacity requirements, two adjustments must be made. First an adjustment must be made to reflect seasonality in product demands and fluctuations in crude supply. No refinery (and associated distribution/marketing facilities) has sufficient crude and product storage capacity to operate every day at maximum capacity unimpeded by inventory problems. Typically, the U.S. refining industry has assumed that a 90 percent efficiency utilization of indicated refinery crude capacity is a realistic target for long-term planning purposes.

EXHIBIT A-2

Products Required From Domestic Refineries in 1985
Thousand Barrels Per Calendar Day

	Total[1] Outturn	Supplied from[2] Existing Capacity	Supplied from New Capacity
asoline	7,132	6,517	615
erosene Jet Fuel	1,359	868	491
istillate Fuel Oil[3]	3,535	2,773	762
esidual Fuel Oil	1,416	1,053	363
etrochemical Feedstocks	1,234	766	468
sphalt	694	514	180
ll Other Products	1,352	1,198	154
Total	16,722	13,689[4]	3,033
ude Processed	16,097	12,825	3,272
Crude Capacity required in 1985, thousand barrels			
Per Calendar Day	17,886	14,250[5]	3,636
Per Stream Day	19,873	15,833	4,040

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1) Part Two, Table A-3 after revisions to gasoline and "All Others".

2) Estimated by authors assuming 90 percent capacity utilization.

3) Including kerosene.

4) Includes 750 natural gas liquids and 114 processing volumetric gain.

5) Part Two, Table A-4, capacity on 1/1/74.

Accordingly, the required crude runs must be divided by 0.9 to determine the "effective" average annual available capacity.

Furthermore, the planning of refining operations must also make allowance for the periods of time that refinery operations must be curtailed or shut down for mechanical repairs and/or routine maintenance. The criterion upon which the engineering design of a refinery processing unit is based is the actual physical rate that the unit must operate during the periods it is in operation (defined as the stream day capacity) rather than the calendar day average achieved over the entire year. The ratio of operating days to 365 is the "stream day factor". We shall follow the technical sub-contractor and assume a value of 0.9. Thus, the stream day operating capacity required of the U.S. refining industry in 1985 is:

$$\frac{16{,}097^{1)}}{0.9 \times 0.9} = 19{,}873 \text{ thousand barrels per day}$$

Table A-4 in Part Two presents an annual schedule of U.S. refinery expansion projects based on a report by the Federal Energy Administration. We shall assume that the expansion schedule (including miscellaneous net additions) is firm through 1976. However, we consider those projects indicated for completion after January 1, 1977 to be speculative. Accordingly, we shall use capacity installations based on Table A-4 through 1976; and shall estimate later capacity installations to balance our forecast of 1985 crude processing requirements.

Table A-4 indicates U.S. refinery capacity as of January 1, 1974, was 14,250 thousand barrels per calendar day. This is equivalent to $(\frac{14{,}250}{0.9} =)$ 15,833 thousand barrels per stream day. Subtracting this latter number from the required crude capacity in 1985 (19,873) indicates that 4,040 thousand barrels per stream day of new capacity needs to be constructed during the 1974/84 time period. The estimated U.S. refinery capacity for January 1, 1977 in Table A-4 is 16,634 thousand barrels per calendar day. Subtracting the January 1, 1974 capacity (14,250) indicates that 2,384 thousand barrels per calendar day will be constructed during this three year period (2,649 thousand barrels per stream day). Therefore, 1,391 thousand barrels per stream day (4,040 - 2,649) needs to be constructed during the 8 year period from January 1, 1977 through 1984, or an annual average of about 174 thousand barrels per stream day.

The resulting "Revised" forecast for new refinery crude capacity is presented in Exhibit A-3. This Exhibit also contains for comparison the "Original" forecast of new capacity developed by TM&S.

3. Downstream Processing Facilities in New Plants

On page II-5 of Part Two is shown the product yield slate originally estimated by TM&S as that which will be required from incremental new domestic refining capacity to be built during 1974/1984. Exhibit A-2 indicates that after adjustments for reduced gasoline consumption, the yield of gasoline from new refining capacity installations is 18.8 volume percent of crude processed.

The important implication of the lower required gasoline yield is in the likely process unit configuration of new domestic refining capacity. The "original" 37 percent gasoline yield forecast by TM&S was sufficiently close to current yields that historical refinery configurations would have been expected to continue to prevail in additions to capacity. This implied that refinery capacity would contain the same percentage of catalytic cracking capacity as exists in U.S. plants (31 percent).

In contrast, the "revised" estimates computed above indicate that gasoline will comprise about 19 percent of refinery outturn. Such a yield can be achieved without conversion to gasoline of higher boiling products. Consequently, we forecast that the only additional catalytic cracking capacity that will be brought on stream during the period 1974-1984 is the 136 thousand barrels per stream day of expansions that have been announced.1)

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1) Oil and Gas Journal, March 24, 1975, p. 15.

EXHIBIT A-3

Forecast of Required Capacity Additions

	"Original"[1]	"Revised"[2]
Year	Thousands of Barrels Per Stream Day	Thousands of Barrels Per Stream Day
1974	684	684
1975	573	542
1976	1,422	1,423
1977	516	173
1978	722	174
1979	247	174
1980	247	174
1981	248	174
1982	247	174
1983	247	174
1984	248	174
Subtotals		
1974-77	3,195	2,822
1978-84	2,206	1,218
Total		
1974-84	5,401	4.040

1) Exhibit A-1

2) See text.

The configuration of the model expansion is designed to meet the product demand structure outlined in Exhibit A-2. All major product demands are met precisely. Within the "All Other Products" category are the demands for lubes and LPG. We permit manufacture of LPG to "float" (i.e., seek it's own natural level) since refineries are not the major source of supply for this product. We ignore the demand indicated for coke since this category includes catalyst coke made by catalytic cracking (which is not used in our model expansion) and any increase in domestic demand could be met by a reduction in exports. We ignore still gas as a discrete product since it is merely an element of internal fuel consumption. To recapitulate: our model expansion is designed to meet the product demands outlined in Exhibit A-2 except for LPG, coke and still gas as just described.

Exhibit A-4 presents the refinery processing and blending summary for the base version (no post-1973 EPA regulations) of the model expansion. The sign convention in the Exhibit is that any value enclosed in parentheses represents consumption of a stream - either in a processing unit or product blend. All units are thousands of barrels per calendar day except hydrogen (millions of standard cubic feet) and sulfur streams (tons per day sulfur equivalent).

The refinery consumes one hundred thousand barrels per day of crude oil and produces liquid products in the ratios specified in Exhibit A-3. Internal refinery fuel consumption is estimated to be 7.3 thousand barrels fuel oil equivalent per day for this type of plant design. Total net liquid product recovery for sale (excluding refinery fuel) is 92.7 percent of crude oil charged.

As stated in Chapter II, the residual fuel product averages 1.2 percent weight sulfur content and composite refinery fuel - 1.6. In order to achieve these levels, all atmospheric bottoms not routed to the vacuum distillation unit are desulfurized to 0.5 percent sulfur content. Thus, the only high sulfur blending component is the vacuum bottoms production in excess of asphalt

EXHIBIT A-4

A. PROCESSING SUMMARY FOR BASE VERSION OF MODEL REFINERY EXPANSION

	Processing Units										
	Atmospheric Distillation	Vacuum Distillation	Catalytic Re-forming and Naphtha Hydro-desulfurization	Distillate Hydrodesul-furization	Vacuum Gas Oil Hydrodesul-furization	Atmospheric Bottoms Hydro-desulfurization	Vacuum Bottoms Hydrodesul-furization	Vacuum Gas Oil Hydrocracking	Hydrogen Generation	Sulfur Plant	Net to Blending (Exhibit A-4 B.)
Petroleum Fractions$^{1)}$											
Finished Products											
Crude Oil	(100.0)										
C1/C2 (Gas)			.9						(.5)		.4
C3/C4 (LPG)	1.4		2.6					.8			4.8
Light Naphtha	4.8										4.8
Heavy Naphtha	18.2		(18.2)								
Middle Distillate	32.4			(32.4)							
Atmospheric Bottoms	43.2	(28.8)				(14.4)					
Vacuum Gas Oil		19.7			(14.5)			(5.2)			
Vacuum Bottoms		9.1									9.1
Reformate-95 RON			13.7								13.7
Desulfurized Distillate-0.1%S				32.4				5.9			38.3
Vacuum Gas Oil-0.3%S					14.5						14.5
Atmospheric Bottoms-0.5%						14.4					14.4
Sulfur and $H_2S^{2)}$											
H_2S			1	25	47	62		19		(154)	
Sulfur Product										146	
Hydrogen$^{3)}$			19.6, (1.8)	(4.0)	(5.8)	(8.9)		(10.4)	11.3		

Units 1) Thousand barrels per calendar day (Gas stated on basis of 6.3 million BTU equals 1 barrel)
2) Short tons of sulfur per calendar day
3) Million standard cubic feed per calendar day

EXHIBIT A-4

EXHIBIT A-4 (cont'd)

	Product Blends								
	Net from Processing (Exhibit A-4 A.)	LPG	Gasoline	Middle Distillate Fuel Oils	Residual Fuel Oil	Petrochemical Feeds	Lube Base Stocks.	Asphalt	Refinery Fuel
Petroleum Fractions[1)]									
Finished Products		3.8	18.8	38.3	11.1	14.3	.9	5.5	7.3
Crude Oil									
C1/C2 (Gas)	.4								(.4)
C3/C4 (LPG)	4.8	(3.8)	(1.0)						
Light Naphtha	4.8		(4.1)			(.7)			
Heavy Naphtha									
Middle Distillate									
Atmospheric Bottoms									
Vacuum Gas Oil									
Vacuum Bottoms	9.1				(1.7)			(5.5)	(1.9)
Reformate-95 RON	13.7		(13.7)						
Desulfurized Distillate-0.1%S	38.3			(38.3)					
Vacuum Gas Oil-0.3%S	14.5					(13.6)	(.9)		
Atmospheric Bottoms-0.5%S	14.4				(9.4)				(5.0)
Sulfur and H_2S[2)]									
H_2S									
Sulfur Product									
Hydrogen[3)]									

Units
1) Thousand barrels per calendar day (Gas stated on basis of 6.3 million BTU equals 1 barrel)
2) Short tons of sulfur per calendar day
3) Million standard cubic feed per calendar day

EXHIBIT A-5

A. PROCESSING SUMMARY FOR EPA VERSION OF MODEL REFINERY EXPANSION

	Processing Units										
	Atmospheric Distillation	Vacuum Distillation	Catalytic Re-forming and Naphtha Hydro-desulfurization	Distillate Hydrodesul-furization	Vacuum Gas Oil Hydrodesul-furization	Atmospheric Bottoms Hydro-desulfurization	Vacuum Bottoms Hydrodesul-furization	Vacuum Gas Oil Hydrocracking	Hydrogen Generation	Sulfur Plant	Net to Blending (Exhibit A-5 B.)
Petroleum Fractions$^{1)}$											
Finished Products											
Crude Oil	(101.4)										
C1/C2 (Gas)			1.2						(.5)		.7
C3/C4 (LPG)	1.4		3.2					.8			5.4
Light Naphtha	4.8										4.8
Heavy Naphtha	19.2		(19.2)								
Middle Distillate	32.4			(32.4)							
Atmospheric Bottoms	43.6	(28.8)				(14.8)					
Vacuum Gas Oil		19.7			(14.5)			(5.2)			
Vacuum Bottoms		9.1					(3.6)				5.5
Reformate-95 RON			13.7								13.7
Desulfurized Distillate-0.1%S				32.4				5.9			38.3
Vacuum Gas Oil-0.3%S					14.5						14.5
Atmospheric Bottoms-0.5%						14.8					14.8
Vacuum Bottoms-1.0%							3.6				3.6
Sulfur and $H_2S^{2)}$											
H_2S			1	25	47	63	23	19		(178)	
Sulfur Product										177	
Hydrogen$^{3)}$			23.6 (1.9)	(4.0)	(5.8)	(9.1)	(3.6)	(10.4)	11.2		

Units 1) Thousand barrels per calendar day (Gas stated on basis of 6.3 million BTU equals 1 barrel)
2) Short tons of sulfur per calendar day
3) Million standard cubic feed per calendar day

EXHIBIT A-5 (cont'd)

	Net from Processing (Exhibit A-5 A.)	Product Blends: LPG	Gasoline	Middle Distillate Fuel Oils	Residual Fuel Oil	Petrochemical Feeds	Lube Base Stocks,	Asphalt	Refinery Fuel
Petroleum Fractions[1]									
Finished Products		4.4	18.8	38.3	11.1	14.3	0.9	5.5	8.0
Crude Oil									
C1/C2 (Gas)	.7								(.7)
C3/C4 (LPG)	5.4	(4.4)	(1.0)						
Light Naphtha	4.8		(4.1)			(.7)			
Heavy Naphtha									
Middle Distillate									
Atmospheric Bottoms									
Vacuum Gas Oil									
Vacuum Bottoms	5.5							(5.5)	
Reformate-95 RON	13.7		(13.7)						
Desulfurized Distillate-0.1%S	38.3			(38.3)					
Vacuum Gas Oil-0.3%S	14.5					(13.6)	(0.9)		
Atmospheric Bottoms-0.5%S	14.8				(11.1)				(3.7)
Vacuum Bottoms-1.0%S	3.6								(3.6)
Sulfur and H_2S[2]									
H_2S									
Sulfur Product									
Hydrogen[3]									

Units
1) Thousand barrels per calendar day (Gas stated on basis of 6.3 million BTU equals 1 barrel)
2) Short tons of sulfur per calendar day
3) Million standard cubic feed per calendar day

demand. This is distributed among residual fuel oil and refinery fuel so as to keep both streams within sulfur requirements.

Hydrogen sulfide produced in the various desulfurizing units is recovered in amine units and converted to elemental sulfur in a Claus Plant. If this H_2S was not "scrubbed" from refinery off gasses, it would end up in the refinery fuel system and exceed the 1.6 percent maximum sulfur content for refinery fuel. Accordingly, 154 tons of sulfur in the hydrogen sulfide is converted to 146 tons of sulfur product (assuming 95 percent recovery) in conventional units.

Exhibit A-5 presents the refinery processing and blending summary for the EPA version of the model expansion. This version makes the same volumes of finished products as does the base version (except for LPG which was allowed to "float"). The significant differences between this version and the base version are:

1. 101.4 thousand barrels per calendar day crude oil intake versus 100.0.

2. Slightly adjusted distillation cutpoints on the crude unit to convert this extra 1.4 thousand barrels of crude to reformer feed (1.0) and atmospheric bottoms (0.4).

3. Increased feed rate (19.2 versus 18.2) and operating severity (100 clear research octane number versus 95) for the catalytic reformer.

4. Slightly increased feed rate (14.8 versus 14.4) to the atmospheric bottoms desulfurizer.

5. Installation of 3.6 thousand barrels per day of vacuum bottoms desulfurization to produce 1.0 percent sulfur product. This is needed to meet sulfur requirements for residual fuel oil (0.5 percent) and refinery liquid fuel (0.7 percent).

6. Increased hydrogen sulfide flow to the sulfur plant (178 tons sulfur per day versus 154) and operation at increased sulfur recovery (99.5 percent versus 95).

7. Increased refinery internal fuel consumption (8.0 thousand barrels per day liquid fuel equivalent versus 7.3) due to the incremental energy consumed to meet EPA's regulations.

8. Total net liquid product recovery for sale is 93.3/101.4 or 92 percent of crude oil processed.

4. Differential Costs due to EPA's Regulations in Model Expansions

Both versions of the model expansion contain hydrogen sulfide recovery and conversion to elemental sulfur (in Claus Plant facilities). The larger plant in the EPA version of the model expansion (178 tons sulfur per day intake versus 154) is needed because of vacuum bottoms desulfurization and expanded atmospheric bottoms desulfurization. H_2S recovery, Claus conversion and Claus tailgas cleanup costs associated with H_2S production from these sources should be allocated to regulations relating to refinery fuel standards and product quality restrictions. Claus Plant tailgas cleanup costs for the plant size needed in the base version should be allocated to regulations requiring reduction of refinery airborne emissions.

Claus tailgas cleanup costs are shown in Table IV-16 of Part Two. The Claus Plant size affected by EPA's regulations in the model expansion (154 short tons per day) is nearly identical to that shown in the right-hand column of Table IV-16 1). Consequently, the cost shown there ($725.4/365 =) of two thousand dollars per day is directly applicable to our model expansion. On a unit basis, then, the cost of Claus Plant tailgas cleanup is two cents per barrel of crude oil processed.

The EPA version of the model expansion requires installation of 3.6 thousand barrels per day of vacuum bottoms desulfurization. A refiner would not physically build a discrete vacuum

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1) 176 long tons per stream day x 0.9 x 0.9 x $\frac{\text{2240 pounds per long ton}}{\text{2000 pounds per short ton}}$ = 160 short tons per day

bottoms desulfurization unit of such a small size. Rather, normal commercial practice would be to build a larger atmospheric bottoms desulfurizer that could also handle this modest volume of vacuum bottoms.

We have no specific cost data for such a hybrid unit. However, the incremental cost of increasing the capacity of an atmospheric bottoms desulfurizer to handle some vacuum bottoms is surely less than the cost of building a discrete small unit for the vacuum bottoms. Hence, a reasonable assumption is that the per-barrel cost of the incremental capacity increase is equal to the average per-barrel cost of a discrete vacuum bottoms desulfurizer of a reasonable size. This cost is $3.94 per barrel of vacuum bottoms feed (Attachment 2 of Part Two). Since incremental vacuum bottoms feed to the hybrid desulfurizer is 3.6 percent of crude oil processed, this EPA cost is ($3.94 x 0.036 =) fourteen cents per barrel crude oil.

Table V-9 in Part Two provides costs for desulfurizing atmospheric bottoms. From this table we can interpolate that a 13.1 thousand barrel per day unit producing 0.5 percent sulfur product will cost $2.60 per barrel. The EPA version of the model expansion requires an atmospheric bottoms desulfurization unit that is 0.4 thousand barrels per day larger than the unit required in the base version. Hence, the cost required here by EPA's regulations is ($\$2.60 \times \frac{0.4}{100} =$) one cent per barrel of crude oil processed.

Accordingly, the total additional cost for reducing the sulfur content of residual fuel oil product sales and internal refinery fuel consumption is 14 + 1 or 15 cents per barrel crude oil processed. Allocation basis equivalent "sulfur-barrels" removed (11,100 barrels per day from 1.2 to 0.5 percent sulfur versus 8,000 barrels per day from 1.6 to 0.7 percent sulfur) indicates that 8 cents should be attributed to residual fuel oil and 7 cents to refinery fuel.

APPENDIX B

DEVELOPMENT OF NET COSTS FOR CONTROL OF AIRBORNE EMISSIONS

This Appendix describes the methodology used to estimate environmental costs for those classes of refineries (particularly small plants) which incur net costs for airborne emission control procedures that are profitable in other plants. There are 100 refineries in the continental United States with refinery capacity less than 20 thousand barrels per day. Total aggregate capacity of these plants is 785 thousand barrels per day. It was reasoned by the technical sub-contractor that all California refineries were in compliance with airborne emission controls at the start of the base period of analysis. The rest of the United States contains 87 small plants totaling 658 thousand barrels per day capacity.

A series of prototype models was defined to characterize the small refinery industry in terms of processing configuration and capacity. A detailed description of these prototype models may be found in Chapter V, Section B.

To restate, the following eleven prototype models are used to simulate the small refining industry:

	Capacity-Thousand Barrels Per Day		
Processing Configuration	2.0	6.0	18.0
"C"-Type	-	6C	18C
"R"-Type	2R	6R	18R
"T"-Type	2T	6T	18T
"A"-Type	2A	6A	18A

Part Two provides detailed data on the various elements of airborne environmental costs for a "typical" small refinery. These data were modified and scaled to fit the prototype models defined above.

Costs to meet the following categories of airborne emission regulations were developed for the prototype refineries:

- Hydrocarbon vapor recovery from storage tanks, loading racks and API separators.
- CO elimination and particulate recovery from catalytic cracker regenerator exhaust gas.
- Sulfur oxide emission reduction from combustion of gaseous fuels and from Claus sulfur plant effluents.

1. Hydrocarbon Vapor Recovery

a. Cost of Controlling Storage Tank Emissions

The capital investments required for tank modifications are based on data derived from Table IV-18 in Part Two. The table indicates that the capital investment costs for converting tanks of 20, 80 and 140 thousand barrels will be 50.6, 85.1 and 119.2 thousand dollars per tank respectively. These costs are shown graphically in Exhibit B-1.

The annualized costs (including product credits) for storage tank conversion were based on basic data for tank sizes and service provided in Table IV-18 in Part Two. The annual costs presented were converted to the basis of dollars per year per tank. For example, the referenced table indicates the total annual cost for conversion of crude storage in a 10,000 barrel per day refinery is $31,800 per year (for 5 tanks of 20,000 barrels each). This represents $6,400 per year per tank. All the individual tank cost elements were calculated from Table IV-18 in Part Two and plotted in Exhibit B-2.

To estimate the storage tank and loading rack costs in the prototype plants, the following product outturn structures were estimated:

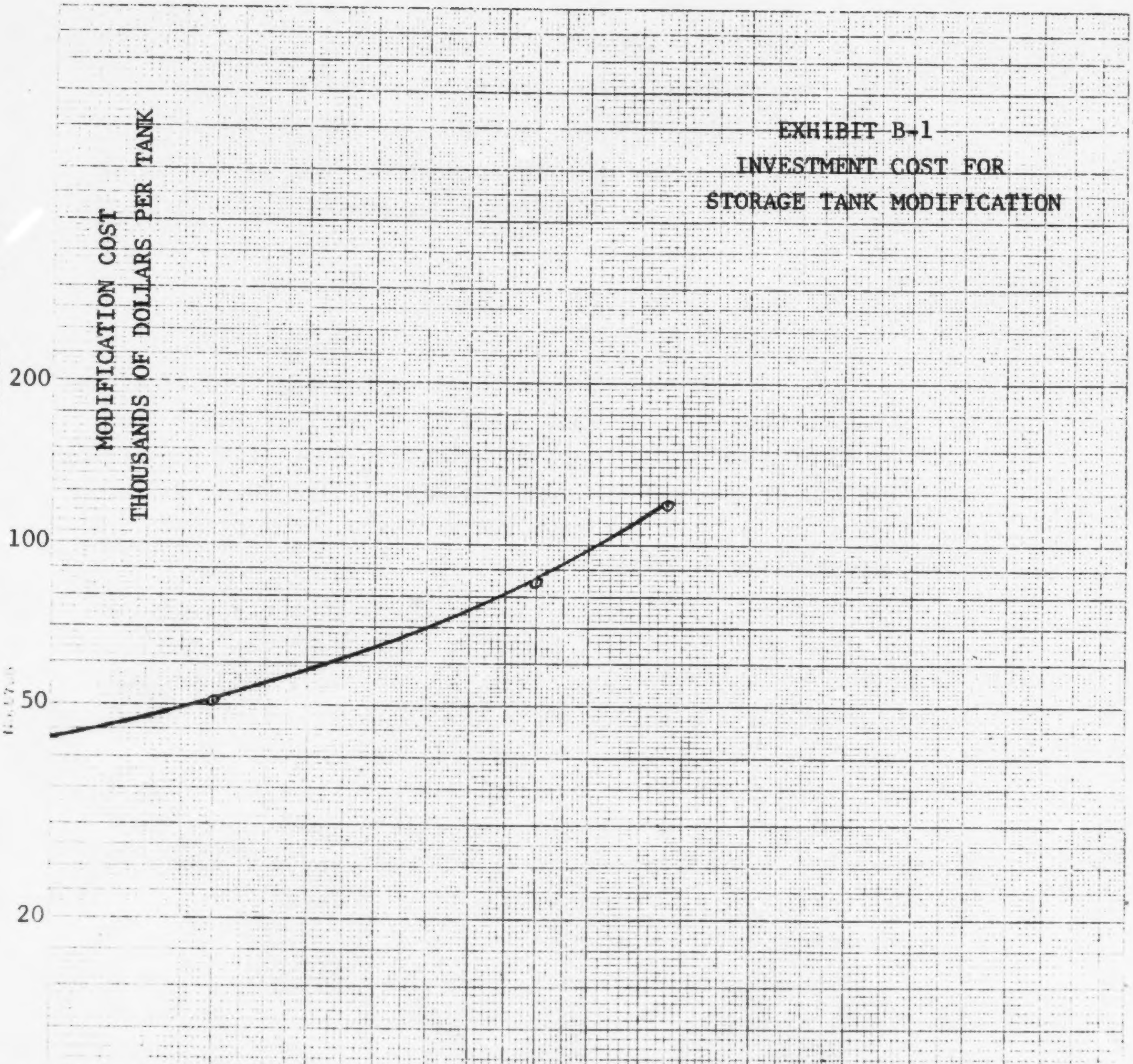
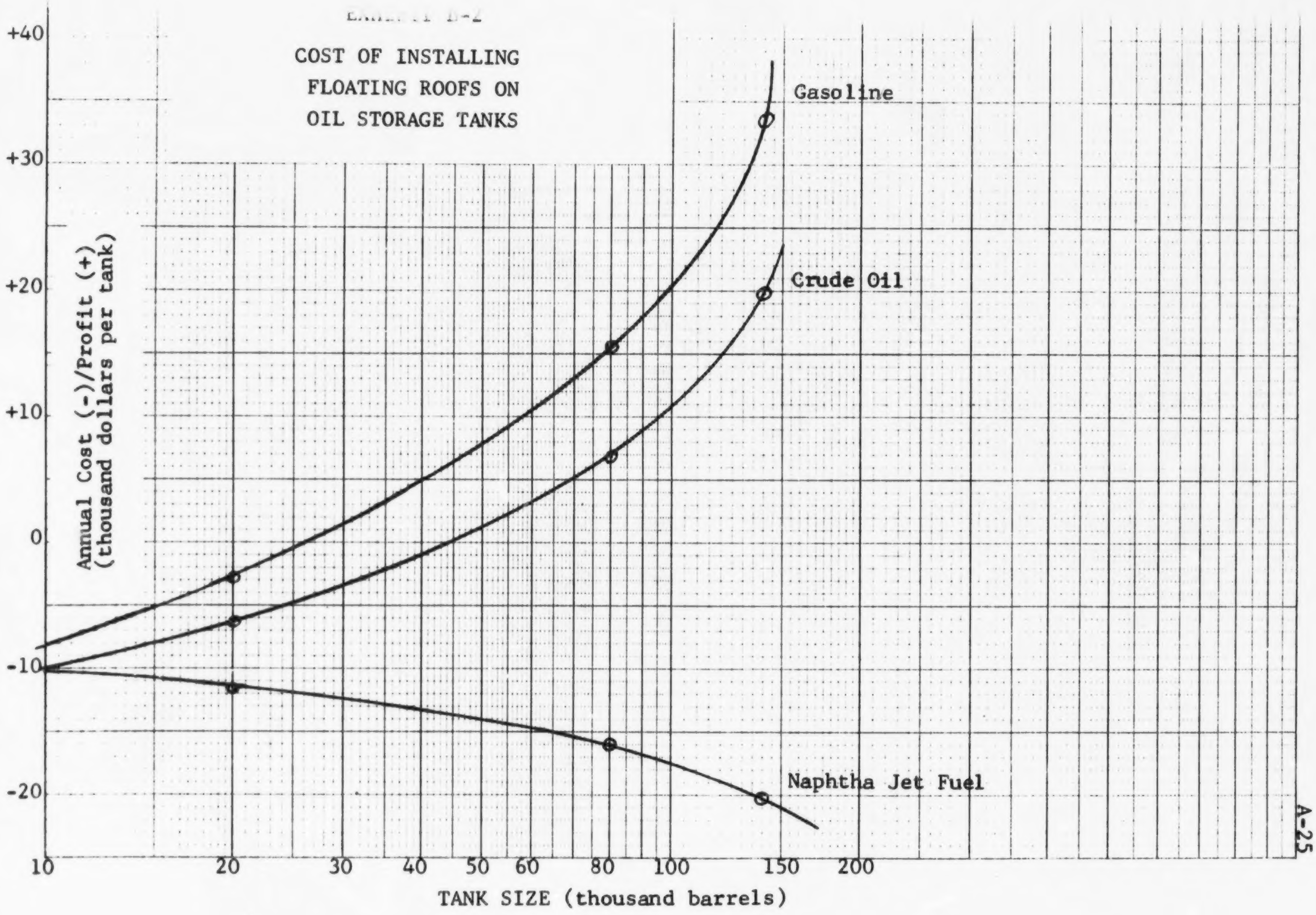


EXHIBIT B-1
INVESTMENT COST FOR
STORAGE TANK MODIFICATION
MODIFICATION COST
THOUSANDS OF DOLLARS PER TANK
200
100
50
20
10
20
50
100
200
TANK SIZE - THOUSANDS OF BARRELS

EXHIBIT B-2

COST OF INSTALLING
FLOATING ROOFS ON
OIL STORAGE TANKS



Product	Outturn-Percent Volume of Crude[1] "C"	"R"	"T"	"A"
Gasoline	70	40	0	0
Jet Fuel (JP-4 grade)	0	0	44	21

It was assumed that about 10 days gross storage would be provided for crude oil, 39 days for gasoline and 25 days for jet fuel as discussed in pages IV-8 and IV-9 in Part Two. Accordingly, Exhibit B-3 was developed which provides the number and size of tanks to be converted to floating roof in each prototype plant.

The foregoing cost and configuration data are combined in Exhibit B-4. Therein are shown the storage tank emission control costs for each prototype refinery. For example, the crude oil costs for model 2R were computed as follows:

1. Crude oil is stored in two 10,000 barrel tanks (Exhibit B-3).
2. The annual (net) cost of installing floating roofs on one 10,000 barrel crude oil tank is $10,000 (Exhibit B-2). So the cost for two tanks is $20,000 per year.
3. Annual crude oil throughput for the 2R model is

   2000 x 365 = 730,000 barrels

   Hence, annual cost is

$$\frac{20{,}000 \times 100}{730{,}000} = 2.74 \text{ cents per barrel}$$

---

[1] Chapter V, Section B. Note that yields shown there exclude natural gas liquids purchased and blended.

EXHIBIT B-3

NUMBER AND SIZE OF STORAGE TANKS TO BE FITTED WITH FLOATING ROOFS

	Prototype Model										
	2T	2A	2R	6T	6A	6R	6C	18T	18A	18R	18C
umber of Tanks											
Crude Oil	2	2	2	4	4	4	4	5	5	5	5
Gasoline	-	-	3	-	-	6	11	-	-	7	12
Jet Fuel	2	1	-	4	2	-	-	5	2	-	-
verage Size Thousand Barrels)											
Crude Oil	10	10	10	15	15	15	15	40	40	40	40
Gasoline	-	-	10	-	-	15	15	-	-	40	40
Jet Fuel	10	10	-	15	15	-	-	40	40	-	-

EXHIBIT B-4

COST OF STORAGE TANK EMISSION CONTROL

	Prototype Model										
	2T	2A	2R	6T	6A	6R	6C	18T	18A	18R	18C
Annual Cost (Thousands Dollars per Year)											
Crude Oil-	20	20	20	32	32	32	32	5	5	5	5
Gasoline-	-	-	24	-	-	30	55	-	-	(35)1)	(60)1)
Jet Fuel-	20	10	-	44	22	-	-	65	26	-	-
Unit Cost (Cents per Barrel Crude Oil)											
Crude Oil-	2.74	2.74	2.74	1.46	1.46	1.46	1.46	.08	.08	.08	.08
Gasoline-	-	-	3.29	-	-	1.37	2.51	-	-	(.53)1)	(.91)1)
Jet Fuel-	2.74	1.37	-	2.08	1.04	-	-	.99	.40	-	-
Investment Cost (Thousand Dollars)											
Crude Oil-	87	87	87	190	190	190	190	320	320	320	320
Gasoline-	-	-	131	-	-	285	523	-	-	448	768
Jet Fuel-	87	44	-	190	95	-	-	320	128	-	-

---

1) Numbers in () indicate a negative cost, i.e., a profitable project.

4. The investment required to install a floating roof on one 10,000 barrel tank is \$43,500 (Exhibit B-1). For two tanks, the cost is \$87,000.

Exhibit B-2 shows that the installation of floating roofs is profitable[1] for gasoline tanks larger than 26,000 barrels, and for crude oil tanks larger than 44,000 barrels. (Such installations are never profitable for jet fuel tanks). These facts must be recognized when computing the total cost of industry conformance to EPA's regulations, for profitable investments are, by definition, costless. The useful data that enables total cost to be properly computed are the refinery sizes for which installation of crude oil tank floating roofs, or gasoline tank floating roofs, are breakeven.

It is shown in Exhibit B-3 that crude oil tankage requirements are dependent only on refinery size and are independent of processing configuration. Hence, a single, size-dependent, "breakeven" point can be derived for crude oil tankage. But there are different gasoline tankage requirements for "R"-type than for "C"-type refineries, so the unit and investment costs are different.

Exhibit B-5 shows that the "breakeven" refinery capacity at which modifying crude oil tankage becomes a "net" cost item is 19,500 barrels per day. There are 85 U.S. refineries in the U.S. outside of California with a capacity below the "breakeven"point.

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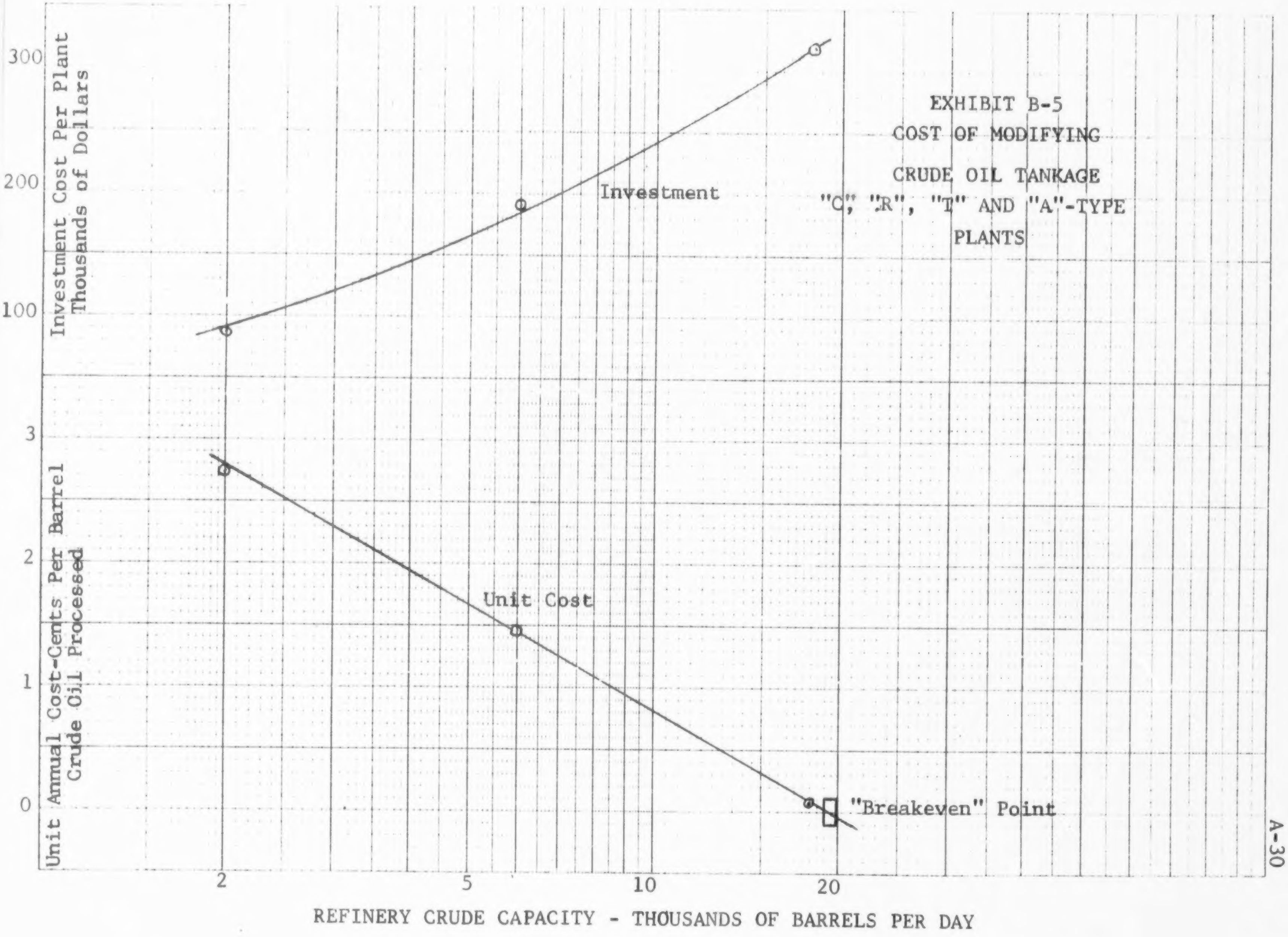
1) That is, it earns a discounted cash flow rate of return of 12 percent or more.

EXHIBIT B-5
COST OF MODIFYING
CRUDE OIL TANKAGE
"C", "R", "T" AND "A"-TYPE
PLANTS



Their average capacity is 7,300 barrels per day. Exhibit B-5 indicates a unit annual cost of 1.2 cents per barrel crude capacity which yields an aggregate annual cost in 1983 of 2.7 million dollars per year for the 85 plants. Investment requirements are 17.4 million dollars. We assumed, similar to the technical sub-contractor, that 80 percent of the aggregate cost to bring existing plants into compliance would be spent by the end of 1977.

Exhibits B-6 and B-7 show that the "breakeven" capacity for modifying gasoline tankage is about 13 thousand barrels per day for both "R" and "C"-type plants. This results in 16 "R"-type and 14 "C"-type plants being impacted. These average 5,900 and 8,000 barrels per day crude capacity, respectively. Total annual costs in 1983 for both types are 1.1 million dollars per year and investment required is 12.9 million dollars.

It was assumed by the technical sub-contractor[1] that the installation of floating roofs on jet fuel tanks was profitable. Consequently, they assumed that 75 percent of existing naphtha jet tankage (100 percent in District V) contained floating roofs as of January 1, 1974, the base period for the study. However, naphtha jet tankage modifications are a net cost item, even for large refineries (Table IV-18). Consequently, an estimated existing fraction of zero for PAD's I through IV seems more reasonable. Thus, aggregate costs are estimated to be four times greater than those shown in Part Two Tables IV-1 and IV-2.

b. Costs of Controlling Loading Rack Emissions

Table IV-9 in Part Two provides cost data for vapor recovery at loading racks. Each refinery in that table was assumed to load 10 percent of crude intake as product over the rack. Thus, costs are provided for loading 1.0 and 6.2 thousand barrels per day of products.

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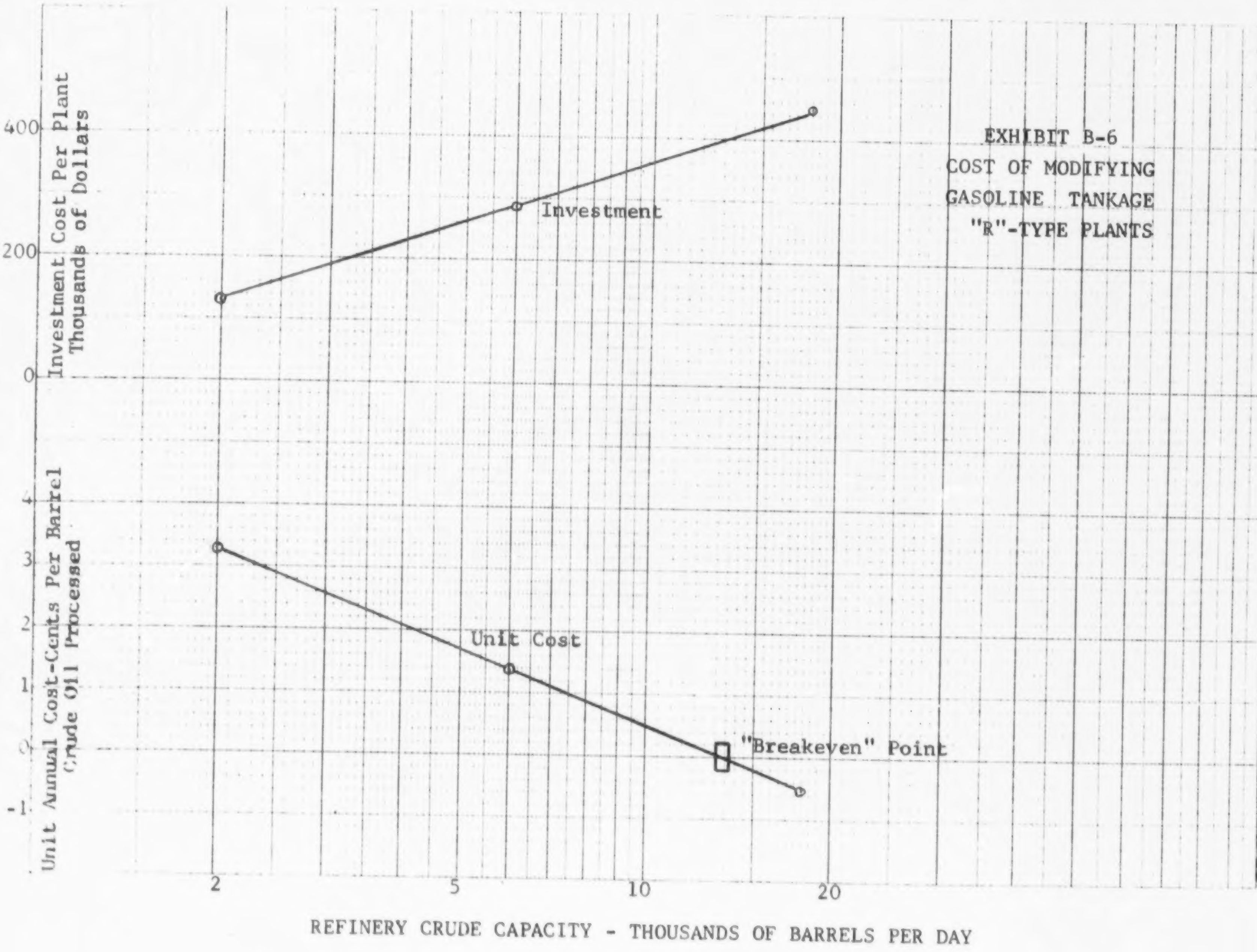
[1] Part Two, page IV-7.

EXHIBIT B-6
COST OF MODIFYING GASOLINE TANKAGE "R"-TYPE PLANTS



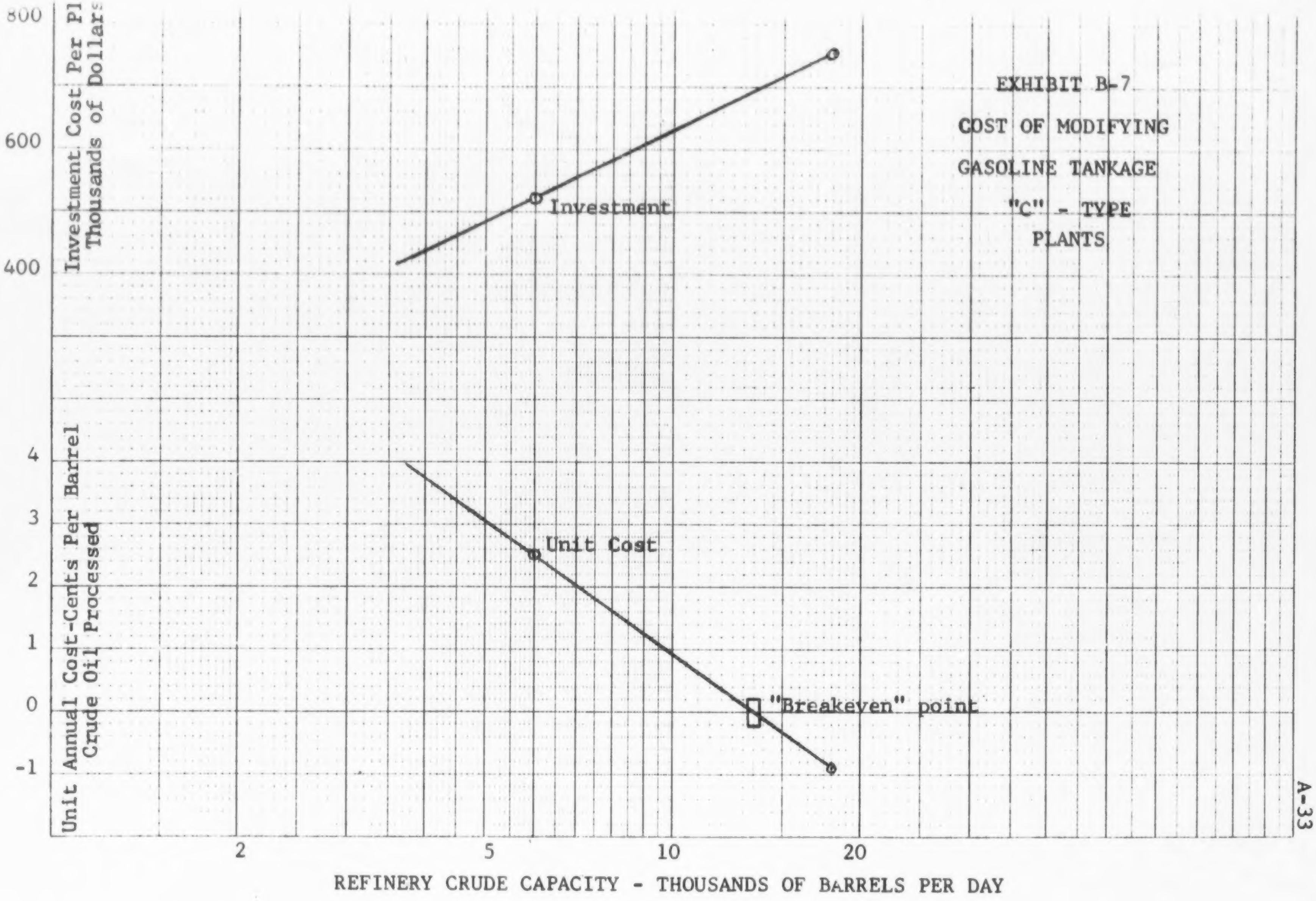


EXHIBIT B-7

COST OF MODIFYING

GASOLINE TANKAGE

"C" - TYPE

PLANTS

For the prototype refineries, it was assumed that there is no rack loading that requires vapor recovery facilities for topping ("T" and "A"-type) plants. Models 2R, 6R, 6C, 18R and 18C were assumed to load 100 percent of gasoline outturn over the rack up to a maximum of 7 thousand barrels per day. Thus, the following costs were developed applying the scale factor for capital-related charges used by the technical sub-contractor in Table IV-9, and a scale factor of 1.0 for all other costs:

	Data From Table IV-9 of Part Two		Prototype Model				
			2R	6R	6C	18R	18C
Volume Loaded-Thousand Barrels Per Day	1.0	6.2	.8	2.4	4.2	7.0	7.0
Cost-Thousand Dollars Per Year							
Capital	43	67	42	53	61	69	69
All Other	(11)	(66)	(9)	(26)	(45)	(75)	(75)
Total	32	1	33	27	16	(6)	(6)

The above costs were restated in units of cents per barrel of crude capacity and are presented graphically in Exhibits B-8 and B-9 for "R"-type and "C"-type plants respectively.

Exhibits B-8 and B-9 indicate the "breakeven" capacities for modifying loading racks to be about 14 and 16 thousand barrels per day for "R" and "C"-type plants respectively. This results in 16 "R"-type and 16 "C"-type plants being impacted which average 5,000 and 8,900 barrels per day respectively. Aggregate annual costs in 1983 are 0.9 million dollars per year. Investment is 5.5 million dollars.

c. Costs of Controlling API Separator Emissions

Investments and associated annual costs for API separator emission control modifications are shown in Table IV-8 of Part Two. The product recovery credits shown therein require modification. Consequently we shall develop new estimates here.

KEUFFEL & ESSER CO.

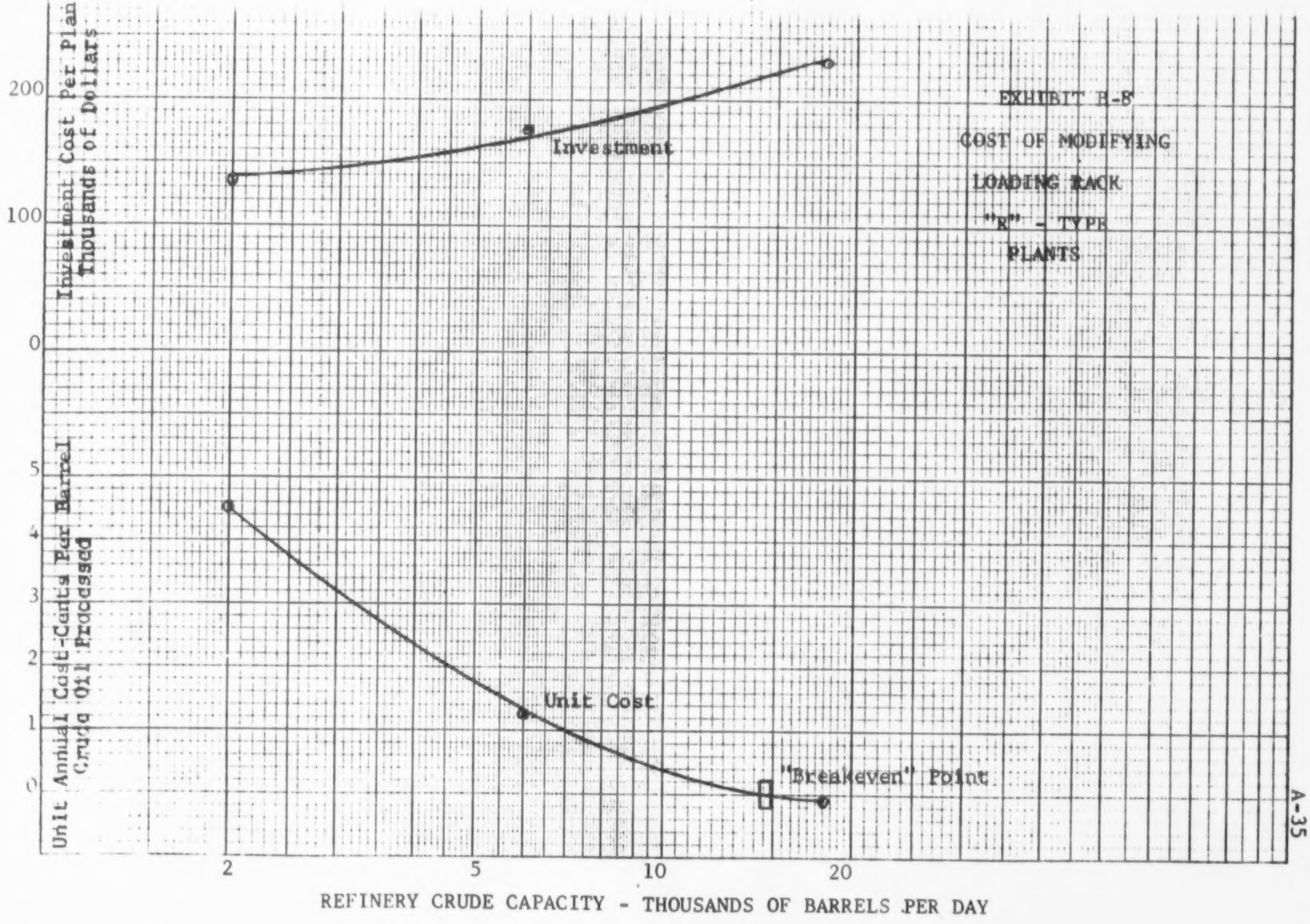


EXHIBIT B-8

COST OF MODIFYING

LOADING RACK

"R" - TYPE

PLANTS

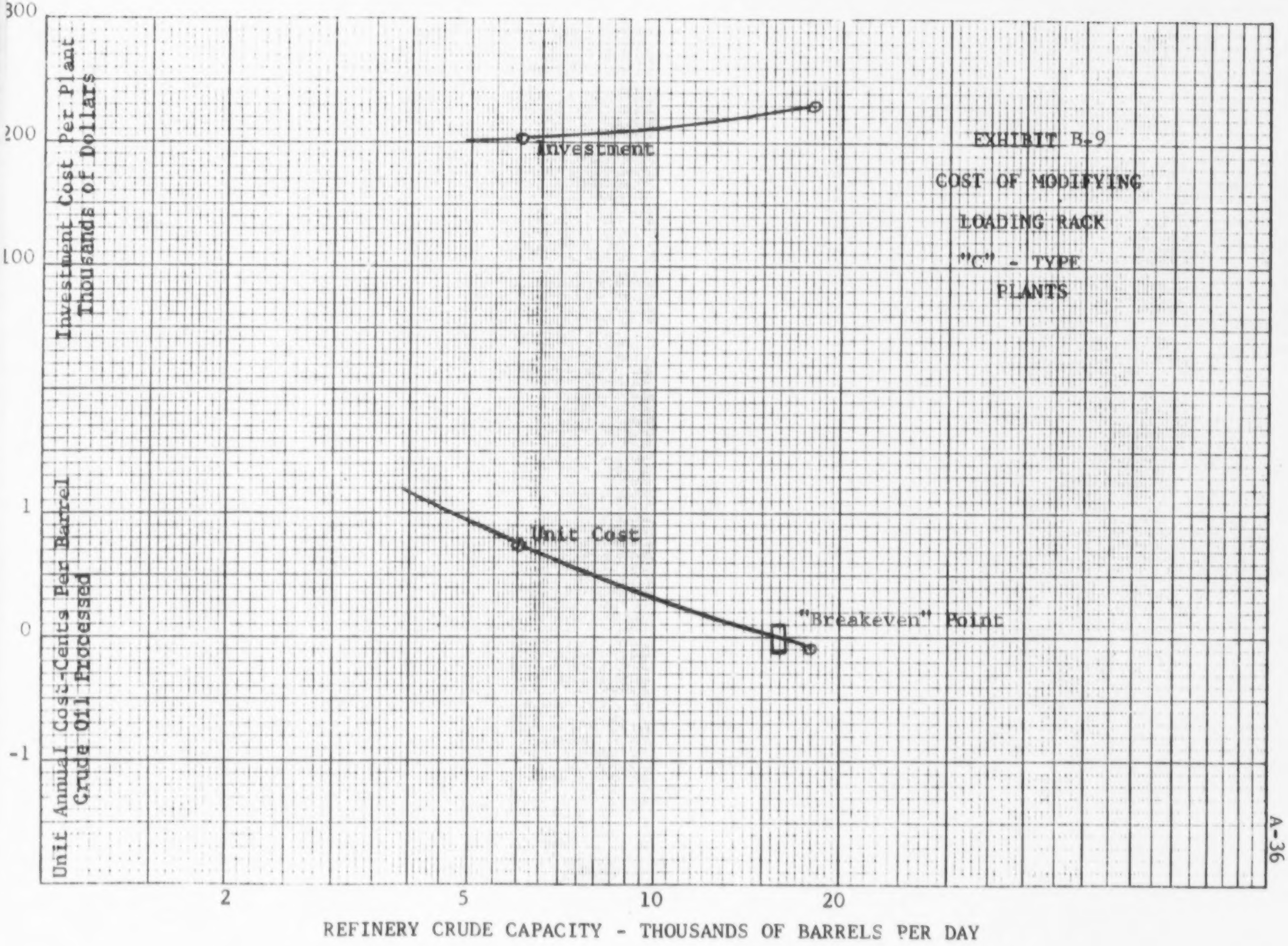


EXHIBIT B-9

COST OF MODIFYING
LOADING RACK
"C" - TYPE
PLANTS

Hydrocarbon vapor losses from covered and from uncovered separators can be computed using a method published by the American Petroleum Institute 1). The method requires estimates of five variables: waste water flow to the separator, entrained oil content of the waste water, ambient temperature, influent temperature, and volatility of the entrained oil (10 percent boiling point is used as the measure of volatility). The following computation is for a typical 100,000 barrel per calender day refinery. The results from this example can be scaled linearly to other crude capacity sizes.

The proper waste water flow to be used in computing API separator vapor recovery is the flow required to meet effluent guidelines. This is the BPCTCA flow rate. (It is not BATEA flow, because most refineries will achieve this lower discharge by recycling treated effluent back to the refinery.) Guideline BPCTCA flows are shown on the bottom of page III-7 of Part Two. Weighting these with the capacities shown in Table III-5 gives an average flow of 32.8 gallons of waste water per barrel of crude oil. For our 100,000 barrel per day model expansion, this is 78,000 barrels per day. The oil content of entering waste water is estimated to be 0.15 percent according to the API. Consequently, oil flow to the separator is 117 barrels per day.

The quantity of inlet oil which would be lost to the atmosphere from uncovered separators depends on the parameters discussed earlier. In Exhibit B-10 we show our estimates of these for two broad regions - the Gulf Coast (PAD III) and the rest of the country, except California (PADs I, II, and IV; PAD District V is not included because it was reasoned that these plants were in compliance with airborne emission requirements

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1) American Petroleum Institute, Hydrocarbon Emissions from Refineries, Publication No. 928, July, 1973.

EXHIBIT B-10

Estimates Of Hydrocarbon Vapor Loss From API Separators

Variable	Geographical Location PAD III	 PADs I, II and IV
Ambient Temperature, °F	69[1]	53[2]
10% Boiling Point, °F[3]	250	250
Influent Temperature, °F[3]	95	87
Percent Volume Loss[4]	8.8	6.6

---

[1] Average for New Orleans and Houston, Statistical Abstract of the United States, 1973

[2] Average for Philadelphia, Chicago and St. Louis, Ibid

[3] SCI estimates

[4] Calculated from correlation given on page 36, API Publication No. 928.

prior to the base date of this analysis). Covers on API separators reduce losses by 85 percent. Hence, net hydrocarbon savings for a 100,000 barrel per day refinery would be 8.8[1] and 6.6 barrels per day, respectively, for the two regions.

Exhibit B-11 combines product recovery credits with costs for the two regions. Exhibits B-12 and B-13 display investment costs and unit annual costs for each region for refineries of different capacities. These exhibits show that medium and large size plants in PAD III will recover enough hydrocarbon to make API separator covers a profitable investment. Only the very largest refineries will experience net savings in the rest of the country.

Exhibit B-12 (for PAD III) indicates that only plants below 50 thousand barrels per day capacity are impacted. The Bureau of Mines Refinery Capacity data as of January 1, 1974, indicates that there were 55 plants with less than 50 thousand barrels per day capacity in PAD III with an average capacity of 13 thousand barrels per day. Using unit annual and investment costs from Exhibit B-12 yields aggregate investment requirements to 1983 of 2.0 million dollars and unit annual costs of 0.2 million dollars.

Exhibit B-13 indicates that plants below 100 thousand barrels per day are impacted in PAD's I, II and IV. There are 106 refineries in this category with an average capacity of 27 thousand barrels per day. Resulting aggregate investment to 1983 is 5.5 million dollars and unit annual costs are 0.7 million dollars.

Since most new refinery installations will be built in units of at least 100 thousand barrels per day crude capacity, there will be no EPA related costs for covering API separators in new plants.

Exhibits B-14 and B-15 summarize investments and annual costs associated with hydrocarbon emission control measures.

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1) 117 barrels per day influent x 0.088 uncovered loss x 0.85 loss reduction by covering = 8.8 barrels per day.

EXHIBIT B-11

Annual Costs for Controlling API Separator Emissions

PAD III

Dollars Per Year	Refinery Size-Barrels Per Day 10,000	61,900	200,000
Product Recovery Credits	(4,091)	(25,228)	(81,545)
All Other Costs[1]	7,740	23,040	46,550
Net Annual Costs	3,649	(2,188)	(34,995)
Unit Cost Cents Per Barrel Crude Oil	.10	(.01)	(.05)

PADs I, II AND IV

Dollars Per Year	Refinery Size-Barrels Per Day 10,000	61,900	200,000
Product Recovery Credits	(3,068)	(18,921)	(61,159)
All Other Costs[1]	7,740	23,040	46,550
Net Annual Costs	4,672	4,119	(14,609)
Unit Cost Cents Per Barrel Crude Oil	.13	.02	(.02)

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1) Composite of Maintenance, Taxes and Insurance, and Capital Charge as detailed in Table IV-8 of Part Two.

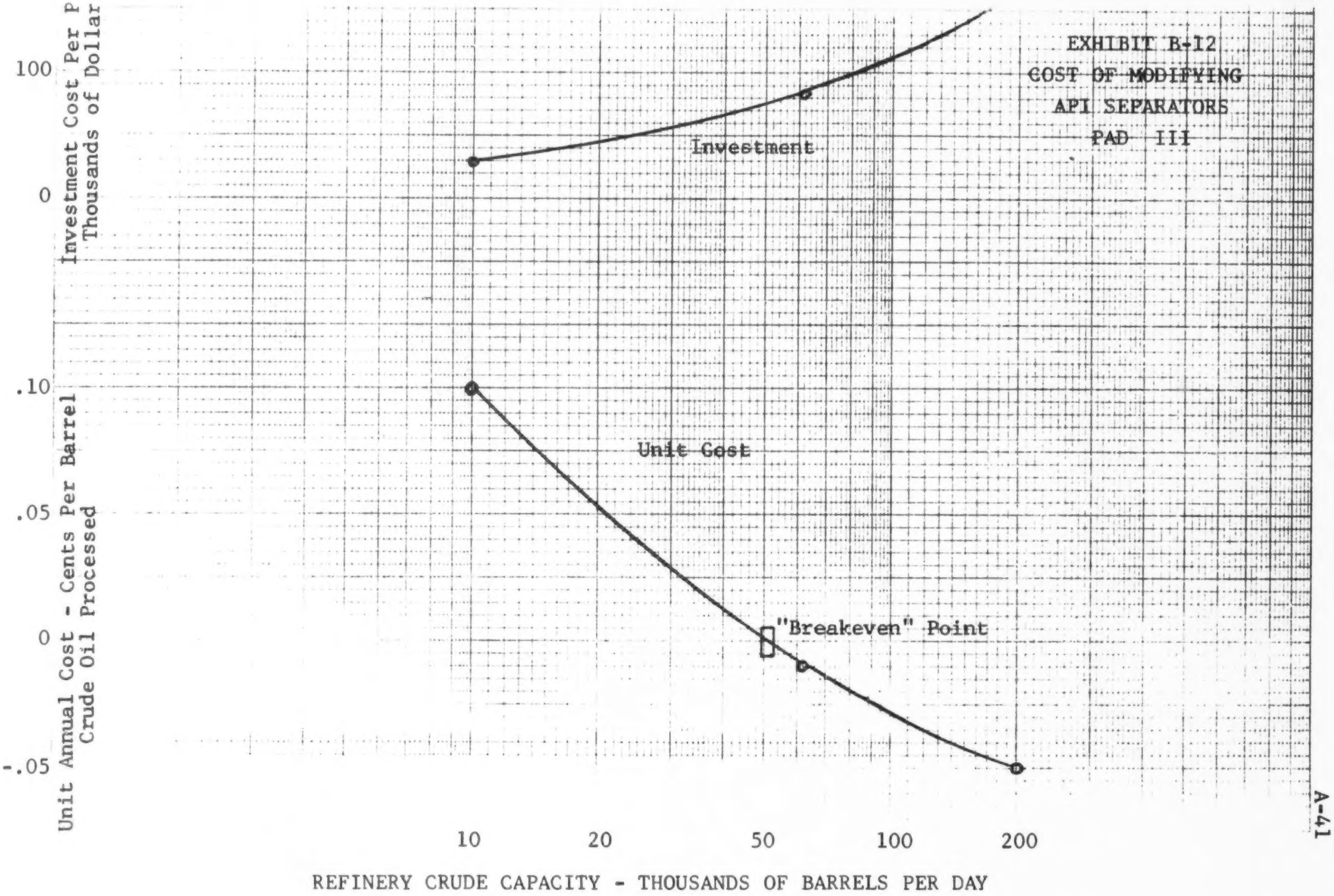

EXHIBIT B-12
COST OF MODIFYING
API SEPARATORS
PAD III

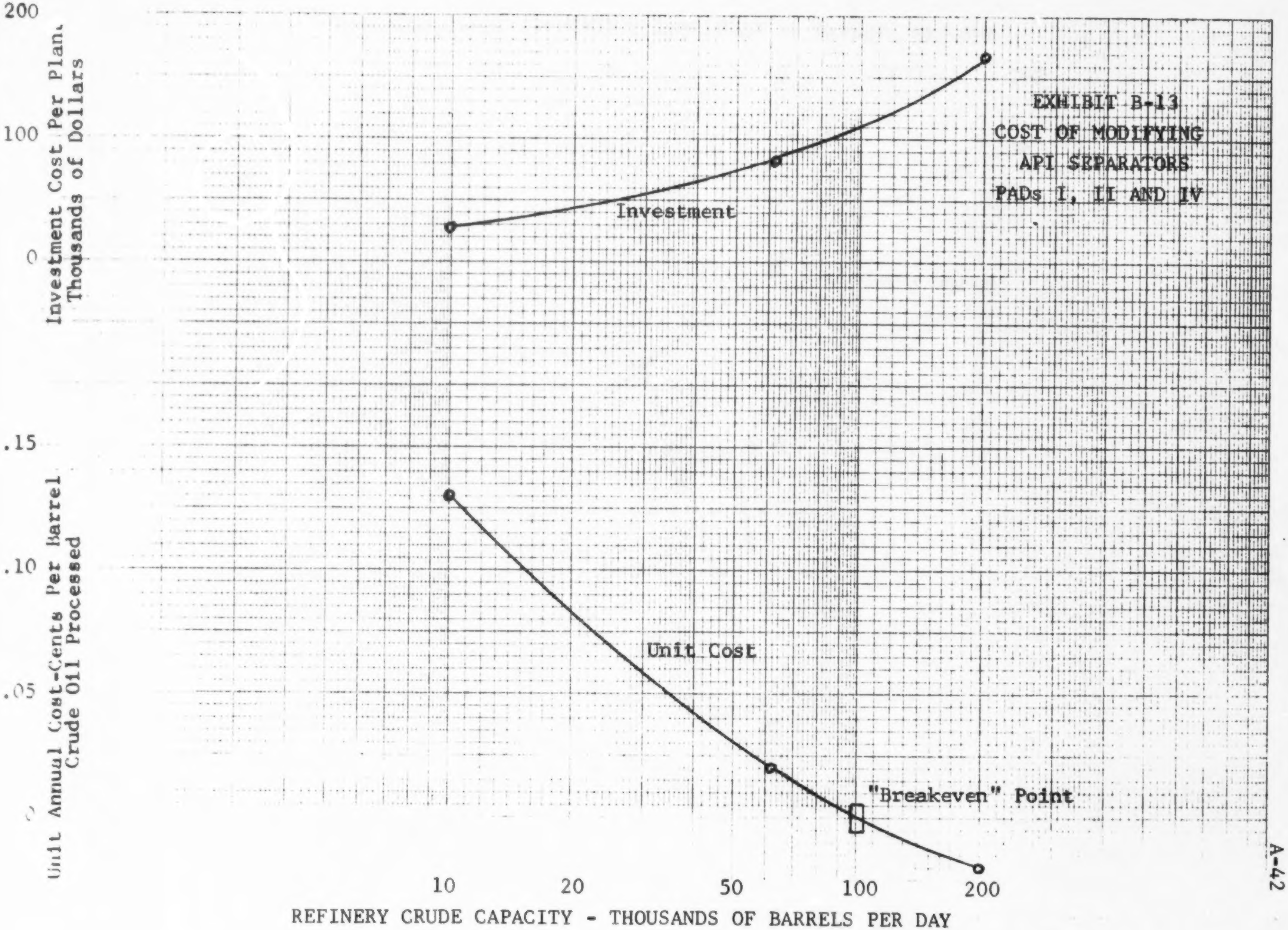

EXHIBIT B-13
COST OF MODIFYING
API SEPARATORS
PADs I, II AND IV

EXHIBIT B-14

CUMULATIVE INVESTMENT FOR HYDROCARBON EMISSION CONTROL MEASURES

(MILLION DOLLARS)

	1974-1977	1978-1982	1974-1982
Tankage			
Crude Oil - Existing	13.9	3.5	17.4
Crude Oil - New	-	-	-
Gasoline - Existing	10.3	2.6	12.9
Gasoline - New	-	-	-
Naphtha Jet - Existing	8.0	2.0	10.0
Sub-Total	32.2	8.1	40.3
Loading Racks			
Existing	4.4	1.1	5.5
New	-	-	-
Sub-Total	4.4	1.1	5.5
Separators			
Existing	6.0	1.5	7.5
New	-	-	-
Sub-Total	6.0	1.5	7.5
TOTAL	42.6	10.7	53.3

EXHIBIT B-15

ANNUAL COSTS FOR HYDROCARBON EMISSION CONTROL MEASURES

(MILLION DOLLARS PER YEAR)

	1977	1983
Tankage		
Crude Oil - Existing	2.2	2.7
Crude Oil - New	-	-
Gasoline - Existing	0.9	1.1
Gasoline - New	-	-
Naphtha Jet - Existing	1.4	1.8
Sub-Total	4.5	5.6
Loading Racks		
Existing	0.7	0.9
New	-	-
Sub-Total	0.7	0.9
Separators		
Existing	0.7	0.9
New	-	-
Sub-Total	0.7	0.9
TOTAL	5.9	7.4

2. CO and Particulate Emission Control from Catalytic Cracking Units

Costs for controlling catalytic cracker regenerator exhaust gas carbon monoxide (CO) emissions were calculated for units with capacities of 6.5 thousand barrels per day. The costs for a CO boiler installation on an existing 31 thousand barrel per day catalytic cracking unit are shown in Table IV-11 in Part Two. It was felt that the 75 percent effective steam utilization assumed there by the technical sub-contractor was too low. We estimate 95 percent to be more realistic and adjusted the steam credit shown in the referenced table accordingly. We used a 0.6 scale factor for capital-related charges and 1.0 for all other costs. Results were:

Annual Cost of CO Boiler (Thousand Dollars Per Year)	Catalytic Cracker Capacity Thousand Barrels Per Day 3.1	2.5	6.5
Steam Credit	(289)	(233)	(606)
Capital	274	241	428
All Other	10	8	21
Total	(5)	16	(157)

The above costs were restated in units of cents per barrel of catalytic cracker feed capacity and are presented graphically in Exhibit B-16. This exhibit shows the "breakeven" capacity for retrofit CO boiler installations to be about 3 thousand barrels per day feed to the catalytic cracker. There are only three catalytic crackers in the U.S. below this capacity. They average 2.0 thousand barrels per day. Resulting annual costs in 1983 are 0.1 million dollars per year and the required investment is 2.2 million dollars.

EXHIBIT B-16

CO-BOILER COSTS

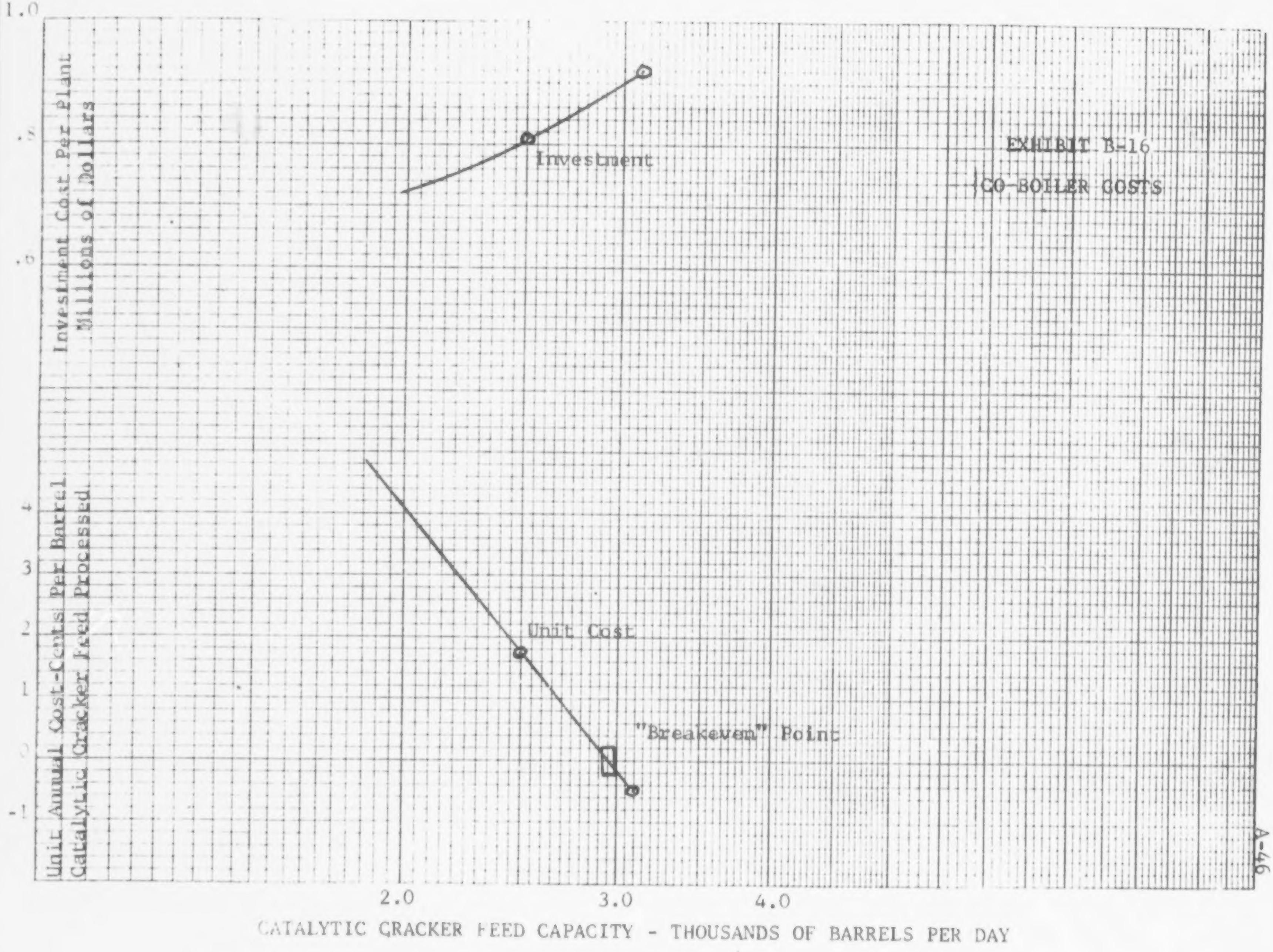

Table IV-5 in Part Two provides a forecast of existing catalytic cracking capacity which requires the addition of electrostatic particulate precipitators. An EPA survey in August 1971 indicated that 29 percent of domestic catalytic cracking capacity was then equipped with precipitators.1) Assuming this same level existed as of January 1, 1974, and using the unit costs developed in Table IV-12, yields a 1983 annual cost of 48.8 million dollars per year and an investment of 156.5 million dollars.

Appendix A (of this Part) noted that 136 thousand barrels per stream day of new catalytic cracking capacity has been announced for the 1974-1983 time period. No other new capacity is expected. Part Two Tables IV-1 and IV-2 indicate that costs for installing precipitators in new catalytic cracking capacity installations built in 1974 are 8.4 million dollars investment and 2.6 million dollars annual cost respectively. Table IV-4 indicates these costs were based on 212 thousand barrels per day catalytic cracking feed capacity. Adjusting these costs to 136 feed capacity yields 5.6 million dollars investment and 1.7 million dollars annual cost.

3. Sulfur Oxide Emission Control

There are three elements to consider within this airborne emission category. They are:

a. Control of refinery gaseous fuel emissions (with amine and Claus units).

b. Tailgas cleanup of Claus Plant effluent

c. Control of refinery liquid fuel emissions (by desulfurizing)

And we must distinguish between new and existing plants.

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1) The Cost of Clean Air (Appendix A), Publication No. 230/3-74-003, U.S. Environmental Protection Agency, April 1974.

For existing plants, Part Two Tables IV-1 and IV-2 present aggregate industry cost estimates for control of refinery gaseous fuels plus Claus plant tailgas cleanup. Table IV-5 forecasts that EPA's regulations will require existing refineries to install the following new control facilities for sulfur in gaseous fuel:

Amine Plants - 2,061 long tons sulfur per stream day
Claus Plants - 5,303 long tons sulfur per stream day

Table IV-15 shows that Claus plant installations usually are profitable in isolation, i.e., once amine facilities are available and excluding tailgas cleanup costs. Hence, we must assume that all refineries that currently contain amine facilities would have opted to install Claus plants independent of EPA's regulations. Thus, we will multiply the aggregate Claus plant costs presented in Tables IV-1 and IV-2 by 0.39 1). Revised costs for control of refinery gaseous fuel and Claus plant tailgas cleanup in existing plants then become:

Time Period	Cost - Million Dollars	
	Capital	Annual*
1974-1977	250	76
1978-1983	63	95

*In last year of period; cumulative since 1973.

In 1973 existing refineries in the U.S. consumed 136 thousand barrels per day of liquid fuels 2) as part of their overall refinery fuel consumption. This will increase to 160 thousand barrels per day when existing refineries run at 90 percent capacity utilization. EPA's regulations will require that the maximum sulfur content of this stream be reduced from 1973 levels (estimated to be 1.6 percent weight sulfur) to 0.7 percent.

We will assume that the "typical" refinery will choose to desulfurize atmospheric bottoms (2.9 percent sulfur) to 0.5

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1) $\frac{2,061}{5,302} = 0.39$

2) Bureau of Mines, Mineral Industry Surveys, 1973.

percent sulfur product to achieve the required 0.7 percent sulfur level in refinery fuel. Thus, the quantity of atmospheric bottoms to be processed is:

$$160 \times \frac{(1.6 - 0.7)}{(2.9 - 0.5)} = 60 \text{ thousand barrels per calendar day}$$

Part Two, page V-13 gives investment and annual costs for desulfurization of atmospheric bottoms to 0.7 and 0.3 percent sulfur weight product in 90 thousand and 14 thousand barrel per day capacity units. We will assume that the average unit U.S. industry costs for existing capacity are adequately represented by an arithmetic average of the unit costs of these four plants. On this basis, cumulative EPA investment costs by 1983 are 107 million dollars, and annual cost in 1983 will be 49 million dollars. We will also assume that the expenditures will be equally divided between the 1974-1977 and 1978-1983 time periods.

The methodology for estimating costs of sulfur oxide emission control in new refinery installations is different from that used for existing plants. In Appendix A, Section 4, we concluded that amine scrubbing/Claus Plant recovery facilities will be required as a part of new refinery capacity installations regardless of EPA's post-1973 regulations. Hence, these costs can be deleted from further consideration in this analysis. However, Claus tailgas cleanup will be required.

In Section B of Chapter IV, we determine the net requirements for new U.S. refinery capacity to be 2,822 thousand and 837 thousand barrels per stream day (equivalent to 2,964 thousand barrels crude processed per calendar day) over the 1974-1977 and 1978-1983 time periods respectively. Exhibit A-5 in Appendix A indicates that the 101.4 thousand barrel per calendar day EPA version of the model expansion (which typifies new refinery capacity installations) will consume 7.3 thousand barrels per calendar day of liquid refinery fuel and require 177 short tons per calendar day of sulfur recovery facilities. In total then, new capacity installations will require 213 thousand barrels per calendar day[1] of liquid refinery fuel to be desulfurized from 1.6 to 0.7 percent weight sulfur in 1983. Also, 5,174 short tons per calendar day of Claus plant tailgas cleanup will be needed.

For the EPA version of the model expansion discussed in Appendix A, it was reasoned that a "typical" new refinery will desulfurize 4.3 percent sulfur vacuum bottoms to 1.0 percent sulfur product to achieve the sulfur levels in refinery fuel required by EPA's regulations. Thus, the needed volume of vacuum bottoms to be desulfurized is:

$$213 \times \frac{(1.6 - 0.7)}{(4.3 - 1.0)} = 58 \text{ thousand barrels per calendar day}$$

Part Two, Attachment 2 provides investment and annual costs per barrel of desulfurized product for vacuum bottoms desulfurization in a reasonably sized plant. Ratioing these unit costs to the total capacity required results in cumulative EPA costs by 1983 of 171 million dollars investment and 83 million dollars annual cost.

Aggregate Claus plant tailgas costs for 5,174 short tons per calendar day capacity (equivalent to 5,703 long tons per stream day) can be obtained by ratic from the cost data presented in Tables IV-1 and IV-2 of Part Two and the capacity data shown in Table IV-5 (9,531.8 long tons per stream day for the 1974-1983 period). Thus, cumulative EPA costs by 1983 are 76 million dollars investment and 27 million dollars annual costs.

4. Unleaded Gasoline Including Lead Phasedown

One important conceptual difference had to be faced before the costs presented in Part Two could be used in this analysis. The technical sub-contractor assumed that the

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1) $\frac{2,964}{101.4} \times 7.3 = 213$ thousand barrels per day

efficiency penalties associated with post-1973 vehicles would, nevertheless, result in the same miles driven in 1983 (and thus, greater gasoline consumption) without consideration that the consumer would respond to this as an "effective" price increase. As a result, page V-8 in Part Two indicates that, for 1985, 0.725[1] million barrels per calendar day more gasoline would be consumed as a result of EPA's regulations with a corresponding increase in crude oil (raw material) consumption of 1.025[2] million barrels per day. Some of this incremental crude oil is to supply internal refining energy and balance other process changes. But most of it is to supply the additional gasoline consumed.

In Chapter III of Part Three we adjusted gasoline consumption to reflect likely consumer response to this "effective" price increase. Thus, Part Two results overstate both investment requirements and annual costs.

The following methodology was used to estimate aggregate investment costs for complying with EPA's regulations concerning unleaded gasoline and phasedown of lead in leaded gasoline.

Table V-2 in Part Two presents the different elements of added refinery costs due to lead regulations for each of the models used by the technical sub-contractor to simulate the U.S. refining industry. It is shown there that only the M-1 Model (7,500 barrels per calendar day crude oil capacity) maintained constant gasoline production (i.e., no revenue change) between scenarios. Thus, we use the capital investment requirements for this plant (after adjusting for economies of scale) as representative of the existing U.S. industry.

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[1] $\frac{4{,}190 \times 10^6}{0.377 \times 365 \times 42} = 0.725 \times 10^6$

[2] $\frac{4{,}770 \times 10^6}{12.75 \times 365} = 1.025 \times 10^6$

Part Two, Chapter IV uses 61,900 barrels per stream day (55,710 per calendar day) as the average crude capacity of existing U.S. plants. Using a 0.6 scale factor, the required investment for the average plant is:

$$2.17^{1)} \times \left(\frac{55,710}{7,500}\right)^{0.6} = 7.23 \text{ million dollars}$$

Total cost for the existing industry then, is

$$\frac{14,250^{2)}}{55.71} \times 7.23 = 1,850 \text{ million dollars}$$

Table V-1 indicates 59 percent of the cumulative investment for M-1 Model must be spent by 1977. We will apply this same percentage to the whole existing industry.

The additional investments to manufacture unleaded gasoline in new refinery capacity installations are derived from the model expansion developed in Appendix A, Section 3. The EPA version required:

a. 1 percent (basis crude oil) increase in catalytic reforming capacity, and increase in operating severity from 95 to 100 clear research octane number.

b. 1.4 percent more crude capacity (some of this was needed to provide energy for fuel oil desulfurization and water treating operations.)

We will assume that 1 percent of the 1.4 percent new crude capacity is required for lead regulations. New crude capacity costs about 2,500 dollars (1974 prices) per stream day per barrel of capacity3). This is 3.09 million dollars additional for the EPA version of the model expansion4).

---

1) Part Two, Table V-1

2) Part Two, Table A-4

3) Turner, Mason and Solomon, private correspondence, July 18, 1975.

4) $\frac{100,000 \times .01 \times 2,500}{.81} = 3.09 \times 10^6$ dollars.

Attachment 1 to Part Two provides investment costs for catalytic reformers designed to produce 90 or 100 clear research octane number product. This reference indicates that reasonably sized plants processing naphtha from light Arabian crude oil will cost 845 and 940 dollars per barrel capacity at the respective octane severities. Ratioing these unit costs to the model expansion results in an additional 2.29[1),2)] million dollars investment.

Total additional investment in the model expansion is 5.34 million dollars (3.09 plus 2.29). This can be extrapolated to represent all new capacity using the procedure described in the previous section. These calculations result in a total of 156 million dollars cumulative investment through 1985 with 120 million being spent through 1977.

The annual costs of EPA's lead regulations are developed in Section C.4. of Chapter IV.

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1) Reformer Feed: $\frac{100,000 \times .01 \times 940}{.81}$ =1.16 million dollars

2) Severity: $\frac{100,000 \times .192}{.81} \times \frac{(940 - 845)}{2}$ = 1.13 million dollar

APPENDIX C

DEVELOPMENT OF COST DATA FOR THE SMALL REFINERY IMPACT ANALYSIS

This Appendix describes the methodology used to estimate environmental costs and other relevant economic data for small refineries for use in the impact analysis. There are 100 refineries in the continental United States with refinery capacity less than 20 thousand barrels per day whose aggregate capacity is 785 thousand barrels per day. The EPA supplied this contractor with specific water discharge quantities for 89 such refineries with aggregate capacity of 701 thousand barrels per day. These data were used as bases for estimates of water effluent control costs.

A methodology was then developed (as discussed in Chapter V, Section A) to obtain estimates of individual non-water environmental costs (airborne, lead removal and fuel oil/refinery fuel sulfur regulations) for each of the 89 plants for which water data was provided. Thus, total environmental cost impacts could be specifically estimated for about 90 percent of the small refinery industry.

1. Effluent Water Control Costs

This section describes the analysis underlying the estimate of water effluent control costs for small refineries. The cost data were taken from Part Two. Unit investment information was found in Table III-8 and the relationship between total annual costs and annual capital charges was determined from the tabulations appearing on pages III-17 and III-18. Waste water flows for each of the refineries in Table III-8 were ascertained from the technical contractor.

The cost data (at 1972 price levels) for the sample of eleven small refineries detailed in Table III-8 were analyzed to determine relationships between cost and waste water flow.

a. Elimination of Once-Through Cooling Water

The two examples both show an investment of $180 per thousand gallons per day flow reduction.

b. In-Plant Flow Reduction

No apparent differences exist between class "A" (topping or topping/reforming) and class "B" (cracking) refineries. Both classes require investments of $1,700 per thousand gallons per day flow reduction.

c. BPCTCA Treatment

The data vary appropriately with quantity treated. For a given flow, class "B" refineries require slightly higher investments than "A" refineries. See Exhibit C-1.

d. BATEA Treatment plus Effluent Reuse

Again the effluent from class "B" refineries is slightly more expensive to treat than that from class "A" plants. See Exhibit C-2.

e. Other In-Plant Investments

This category includes measures to improve the quality of waste water; e.g., sour water stripping, elimination of barometric condensers, and collection of multiple effluents into one stream. As would be expected, these expenditures varied with refinery size rather than with waste water flow rate. See Exhibit C-3.

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EXHIBIT C-1

COST OF BPCTCA TREATMENT OF REFINERY EFFLUENT WATER

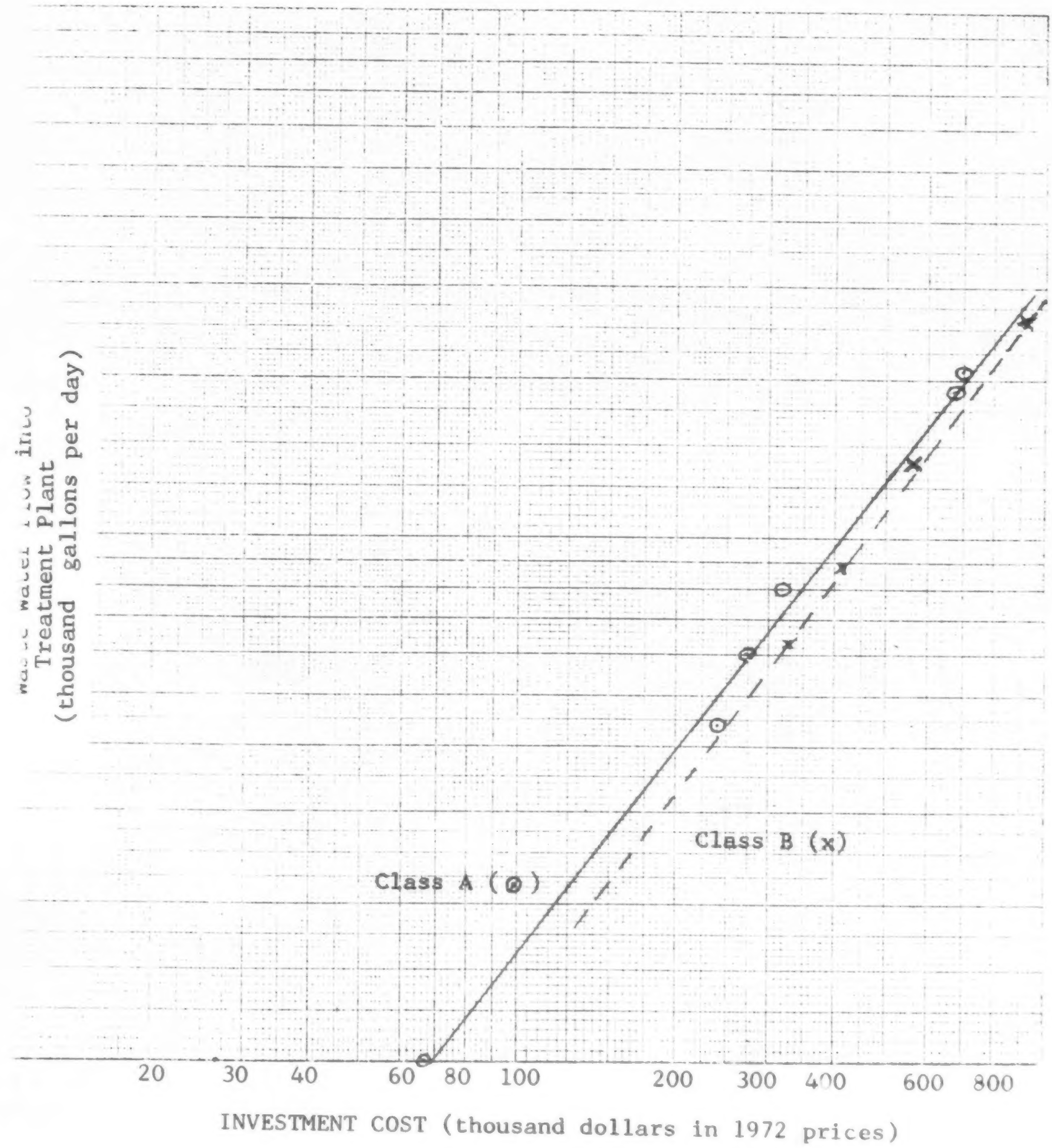


EXHIBIT C-2
COST OF BATEA TREATMENT OF REFINERY EFFLUENT WATER PLUS EFFLUENT REUSE

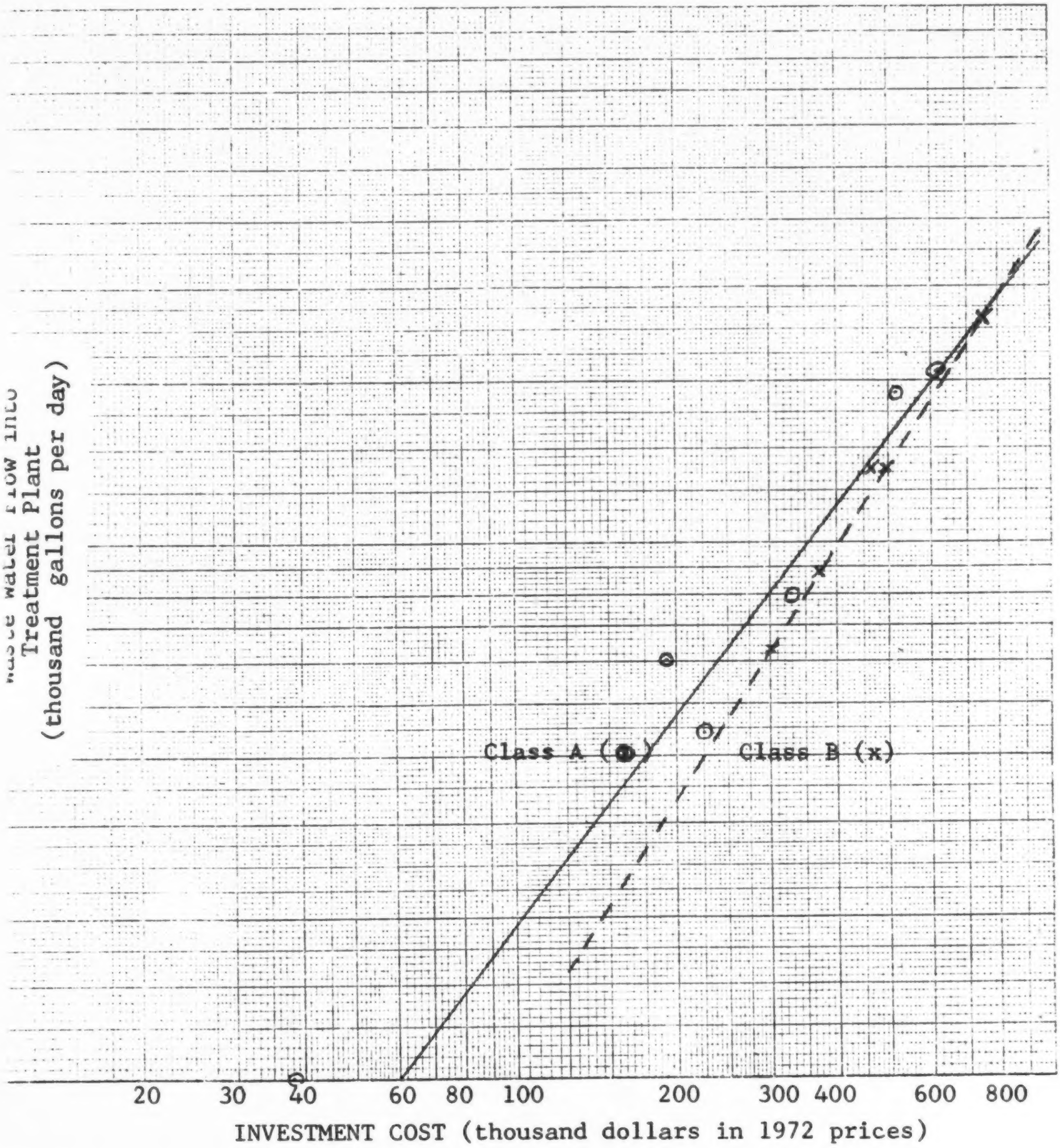
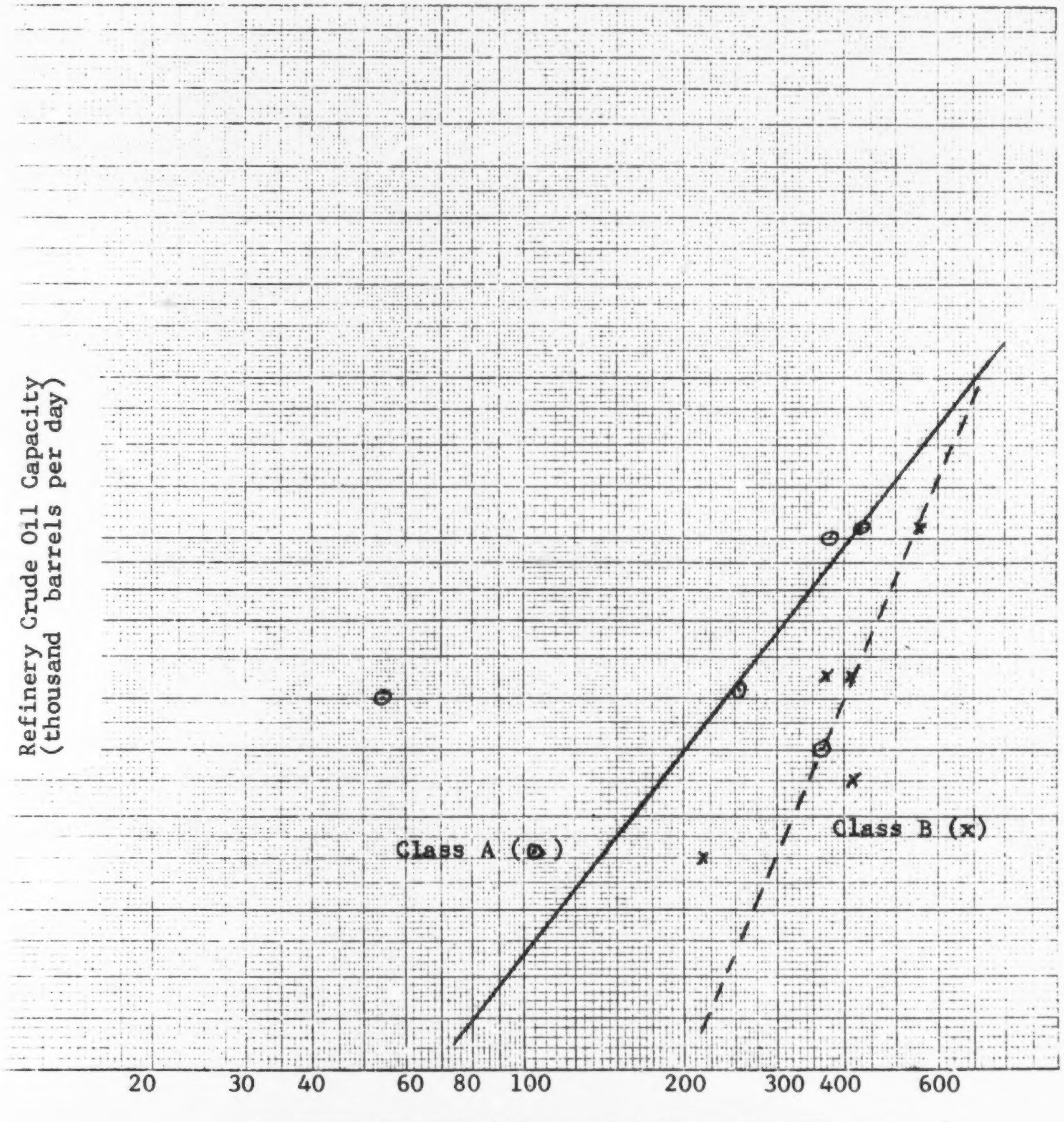


EXHIBIT C-3
COST OF "OTHER IN-PLANT" INVESTMENTS



A set of model refineries was defined so that generalized waste water control cost curves could be developed. Five levels of waste water flow varying from 1 to 400 gallons per barrel of crude oil capacity were assigned to class "A" refineries of 2, 6 and 18 thousand barrels per day throughput and to class "B" refineries of 6 and 18 thousand barrels per day. For each of the resulting thirty models, investment costs (in 1972 prices) were determined for each of the five steps listed above. On the advice of the technical sub-contractor, the total 1972 investment cost for each model was increased by 40 percent to bring it to a 1974 basis.

For existing small refineries the ratio of total annual cost of water effluent control to annual capital charges is 1.38 (Part Two, page III-18). For any refining investment with a 12 percent return, the ratio of annual capital charges to investment is 0.258 (page II-2). Hence, the derived investment costs (1974 dollars) were changed to total annual costs (1974 dollars) by multiplying by (1.38 x 0.258 =) 0.36.

Results of the model refinery calculations are plotted in Exhibits C-4 and C-5. Water effluent control costs vary from 5 to 40 cents per barrel crude oil processed.

2. Airborne Emission and Product Sulfur Control Costs

Costs to meet the following categories of airborne emission regulations were developed for the prototype refineries:

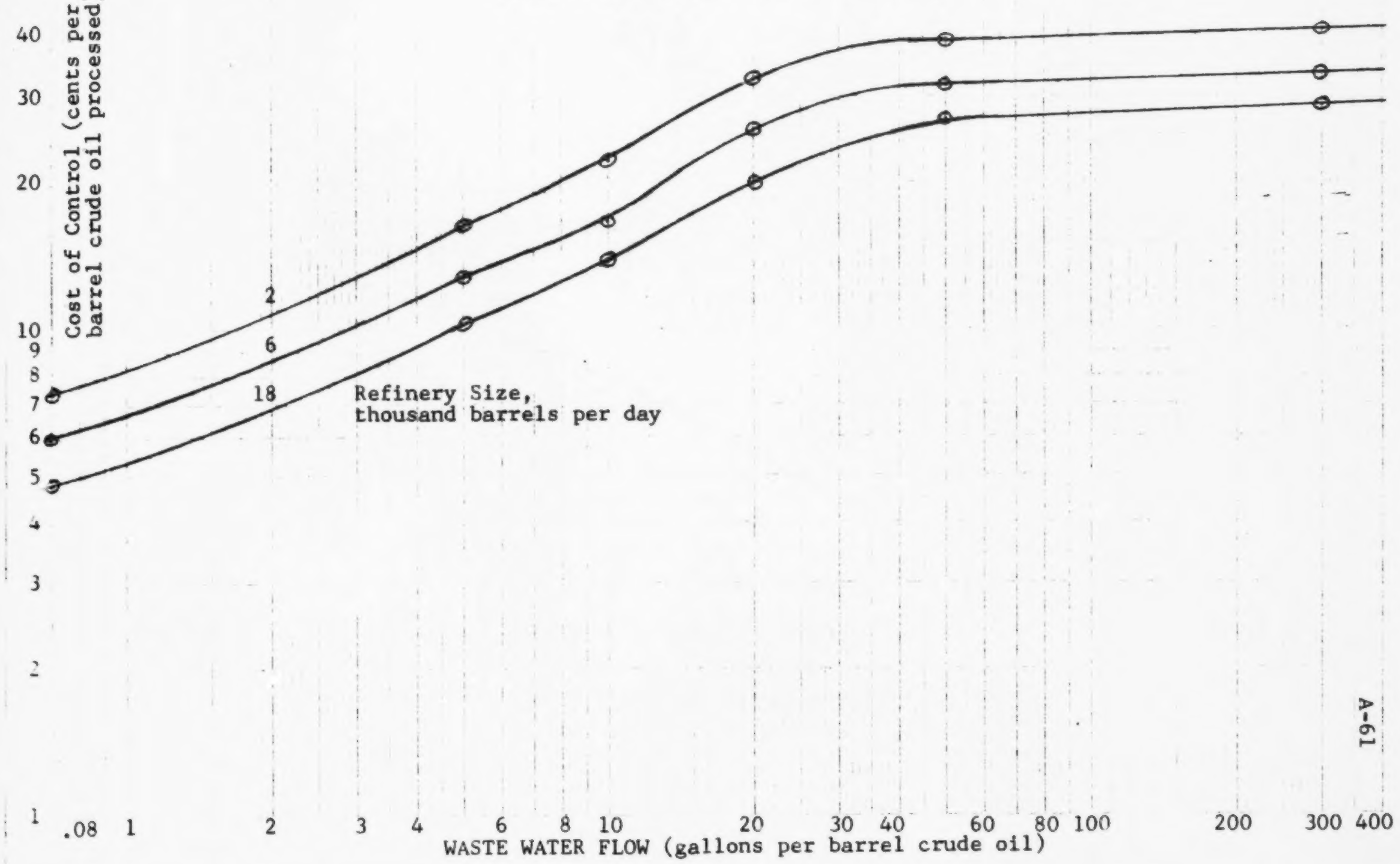
a. Hydrocarbon vapor recovery from storage tanks, loading racks and API separators.

b. Particulate recovery and CO elimination from catalytic cracker regenerator exhaust gas.

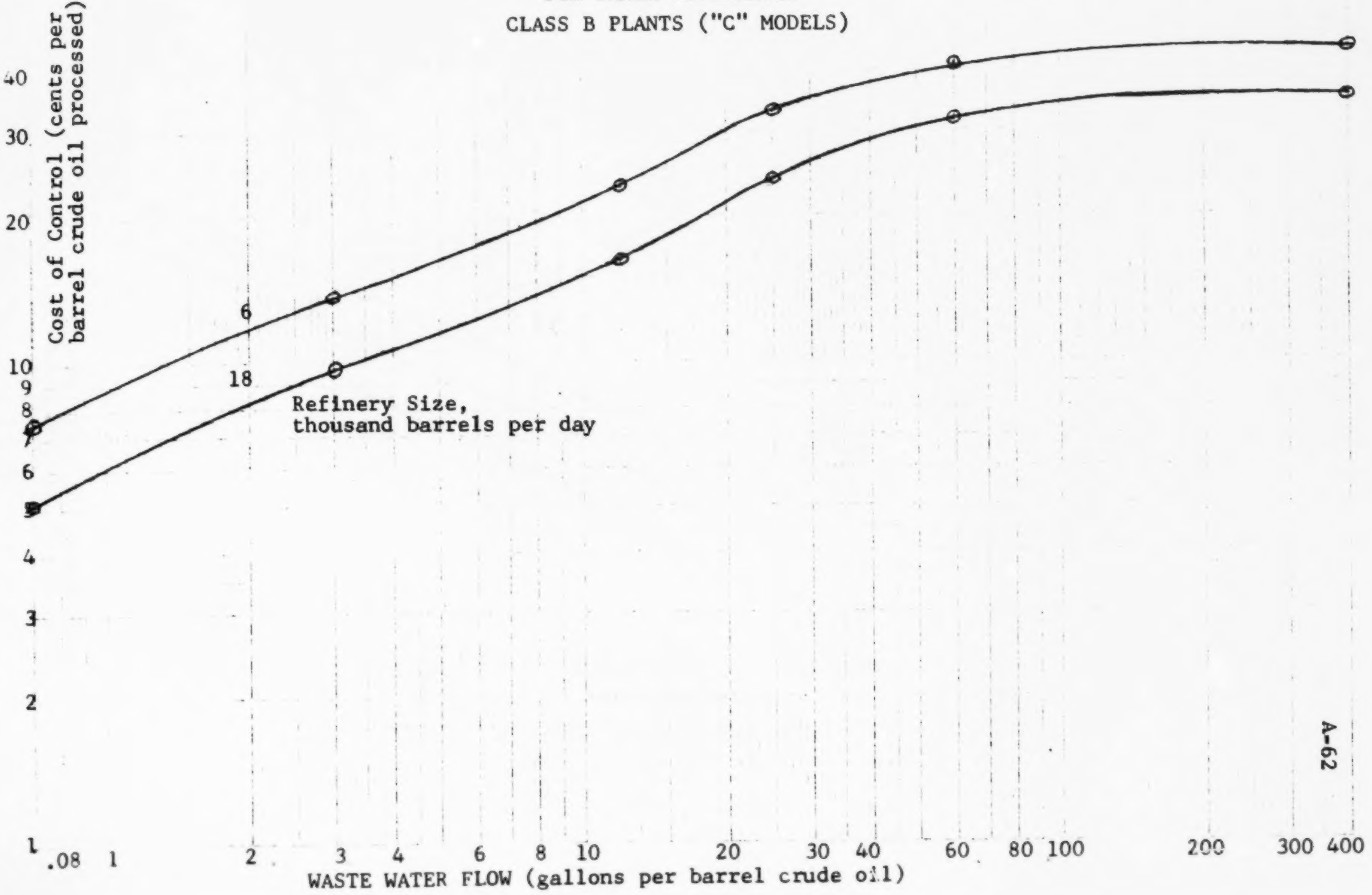
c. Sulfur oxide emission reduction from combustion of gas and liquid refinery fuel and from Claus sulfur plant effluents.

(Since the technology for meeting sulfur regulations in several of the prototype configurations is the same as that used to control sulfur in residual fuel oil production, joint costs

WATER EFFLUENT CONTROL COSTS FOR
SMALL REFINERIES
CLASS A PLANTS ("T" AND "R" MODELS)



WATER EFFLUENT CONTROL COSTS
FOR SMALL REFINERIES
CLASS B PLANTS ("C" MODELS)



for sulfur control of both refinery fuel and residual fuel oil will be developed later in this section.)

a. Hydrocarbon Vapor Recovery

The methodology for calculating costs for storage tank emission control in the prototype models is developed in Appendix B, Section 1.a. and results are presented in Exhibit B-4.

The methodology for calculating costs for controlling loading rack emissions is developed in Appendix B, Section 1.b. and results for the prototypes are presented in Exhibits B-8 and B-9.

The methodology for calculating costs associated with controlling API separator emissions is presented in Appendix B, Section 1.c. Exhibit B-11 shows annual costs for typical 10,000 barrel per day refineries in PAD III and in PAD's I, II, and IV. To obtain costs for our prototype models, we shall average these two regions, linearily adjust product credits, and modify all other costs using a 0.6 scale factor (since all other costs are capital-related). The above calculations yield the following estimates of annual costs:

	Refinery Size-Barrels Per Day		
Cost-Thousand Dollars Per Year	2,000	6,000	18,000
Product Recovery Credits	(.7)	(2.1)	(6.4)
All Other Costs	2.9	5.5	10.6
Net Cost	2.2	3.4	4.2

b. CO and Particulate Emissions from Catalytic Cracking

The methodology for controlling CO emissions from catalytic cracking is developed in Appendix B, Section 2. Results shown therein indicate that only prototype model 6C (six thousand barrels per day) is impacted. It experiences an annual cost of 16 thousand dollars.

The costs for the addition of a precipitator to prototypes 6C and 18C were adjusted from Table IV-13 in Product Two using the same methodology as for CO boiler installation. Results were:

	Catalytic Cracker Capacity Thousand Barrels Per Day		
Cost-Thousand Dollars Per Year	3.1	2.5	6.5
Capital	110	97	172
All Other	2	2	4
Total	112	99	176

c. Sulfur Regulations

This section will develop the methodology and associated costs for the prototypes to:

- Reduce average refinery fuel sulfur content from 1.6 to 0.7 percent weight.
- Reduce sulfur content of residual fuel oil product from 1.2 to 0.9 percent weight.
- Achieve Claus plant tailgas cleanup (for "C"-type plants).

The prototypes will respond differently to the above regulations. The "T" and "R" responses are quite similar. These plants process low sulfur crude oils and produce such little volume of hydrogen sulfide from refinery processing that they will not require amine scrubbing and associated sulfur recovery facilities. Both plants make 37 percent net residual fuel production; "T" plants consume 3 percent refinery fuel and "R" plants consume 6 percent. Thus, to reduce residual fuel oil sulfur content by 0.3 percent weight (1.2 to 0.9) and refinery fuel by 0.9 (1.6 to 0.7) requires an average sulfur reduction of residual stocks of 0.345 in "T" plants[1] and 0.384 in "R" plants.

---

[1] $\frac{(37 \text{ percent} \times 0.3) + (3 \text{ percent} \times 0.9)}{40} = 0.345$

The crude oil price premiums that these types of small refineries must pay will be determined by the international marketplace and are estimated as follows. Within the low-sulfur crude oil category, price differentials for crudes of differing sulfur contents will be set by the yields and sulfur contents of residual fractions[1]. The price premium for lower sulfur residual fuel oil will reflect the costs of desulfurizing atmospheric bottoms in large refineries. This cost is about one dollar per barrel per percent sulfur removal[2].

The residual fuel oil yield from the low-sulfur crude oil assumed here is 35 percent. Hence, the cost of reducing the sulfur level of residual fractions in "T" plants by 0.345 percent weight (by buying a lower sulfur crude oil) is 0.35 x 0.345 x 100 = 12.1 cents per barrel of crude oil processed. The increased crude oil cost for "R" plants is 13.4 cents per barrel. Of course, increased product revenues will result from producing these lower sulfur grades of fuel oils (Chapter II, Section C) which will partially offset the crude price increases. This will be reflected later in the profitability analysis.

"C" plants will respond to EPA's sulfur regulations in a somewhat different way than "T" and "R" plants. First, "C" plants must purchase lower sulfur crude oil to reduce the sulfur content of residual fuel oil product by 0.3 percent. This will cost 10.5 cents per barrel crude oil processed[3]. This lower sulfur crude oil will also cause the sulfur content of the liquid components of refinery fuel to be reduced by 0.3 percent.

We estimate that by 1983 "C" plants' refinery fuel will consist of byproduct gas (equivalent to about 3 percent of crude oil) and liquid fuel (about 5 percent). In the 18C prototype, fuel consumption is:

---

[1] The total price differentials between generic "high-sulfur" and "low-sulfur" crude oils will also reflect premiums for metallurgy, distillate desulfurization, etc.

[2] Part Two, page V-13.

[3] 35 percent residual x 0.3 percent sulfur reduction x 100 cents per percent reduction.

$$\frac{18{,}000 \times 0.08 \times 350 \text{ pounds per barrel}}{2{,}240 \text{ pounds per long ton}} = 225 \text{ long tons per day}$$

Of this, 85 tons (three-eighths) are gas and 140 tons are liquid. Overall fuel sulfur content must be reduced from 1.6 to 0.7 percent, or (225 x .009 =) 2.0 tons per day. As stated above, sulfur content of the liquid portion of refinery fuel will be reduced by 0.3 percent, or (140 x .003 =) 0.4 tons per day. So sulfur content of the gas portion must be reduced by 1.6 tons per day.

Tables IV-14 and IV-15 in Part Two provide annual costs for 8.8 long tons per day of sulfur recovery. We shall scale these costs by modifying capital-related charges with an 0.6 scale factor and adjusting all other costs and credits (except labor) linearly. Since amine scrubbing/Claus facilities are required even in the absence of EPA's post-1973 regulations, there are no additional labor costs in this analysis. Results are:

		"C"-Type Refinery Size Thousand Barrels Per Day	
		6	18
Sulfur Plant Size Long Tons Per Day	8.8	0.5	1.6
Amine Costs Thousand Dollars Per Year			
Capital	101	20	39
Variable	33	2	6
Labor	-	-	-
Total	134	22	45
Claus Costs Thousand Dollars Per Year			
Capital	110	21	43
Variable	(78)	(5)	(14)
Labor	39	-	-
Total	71	16	29

The "C" plants must also install tailgas cleanup for Claus Plant effluent gases. We will estimate required capacity to be equivalent to 70 percent of refinery incoming sulfur. Thus, for 18C:

$$\frac{18{,}000 \times 300 \text{ pounds per barrel} \times .0045 \text{ fraction sulfur} \times .7}{2{,}240 \text{ pounds per long ton}}$$

$$= 7.6 \text{ long tons per day}$$

Table IV-16 in Part Two provides costs for tailgas cleanup. We will scale capital-related charges using an 0.6 scale factor and modify variable costs and credits on a linear basis. We shall assume constant labor costs of 20 thousand dollars per year for each plant size. Results are:

		"C"-Type Refinery Size Thousand Barrels Per Day	
		6	18
Sulfur Plant Size Long Tons Per Day	8.8	2.5	7.6
Claus Tailgas Costs Thousand Dollars Per Year			
Capital	86	40	79
Variable	5	2	4
Labor	20	20	20
Total	111	62	103

The response of "A" plants to EPA's sulfur regulations is quite different from the other prototypes. These refineries will continue to process high sulfur crudes. But, because almost no sulfur is converted to hydrogen sulfide in their refining operations, amine scrubbing/Claus recovery facilities will not be required. However, "A"-type plants still must meet the tighter standards for fuel oil products (0.9 versus 1.2 percent weight sulfur) and for internal fuel consumption (0.7 versus 1.6 percent sulfur).

"A" plants produce 24 percent fuel oil products and consume 5 percent refinery fuel (essentially all liquid). If the "A" plant is located adjacent to a refinery which contains fuel oil desulfurization facilities of normal commercial size, then one could expect suitable exchanges and/or processing agreements could be consumated to enable the "A" plant to achieve sulfur reduction at a "competitive" cost of one dollar per barrel per percent sulfur removed. This would result in a net cost increase to "A" plants of 11.7 cents per barrel1).

For those "A" plants not near refineries with fuel oil desulfurization facilities, additional transportation costs would be involved to physically ship the high sulfur stocks and receive low-sulfur blending components. If we assume the high-sulfur stocks to be shipped contain 2.5 percent weight sulfur and the products received to average 0.3 percent weight, then the percent volume of crude to be exchanged is 5.32). This has to be shipped both ways. We estimate that transportation and other associated costs will average no more than four cents per gallon exchanged, which amounts to a penalty of 8.93) cents per barrel crude oil processed. This must be added to the desulfurization processing cost of 11.7 cents per barrel crude oil previously developed. Thus the composite sulfur penalty for "A" plants is 20.6 cents per barrel crude oil processed.

d. Summary

The joint costs of reducing the sulfur content of residual fuel oil and refinery liquid fuel were computed as crude oil price increases for prototypes "T", "R" and "C". These are:

"T" - 12 cents per barrel crude oil
"R" - 13 cents per barrel crude oil
"C" - 11 cents per barrel crude oil

---

1) $(.24 \times 0.3 \times 100) + (.05 \times 0.9 \times 100) = 11.7$ cents per barrel crude oil.

2) $\frac{24\ (0.3) + 5\ (0.9)}{(2.5 - 0.3)} = 5.3$ percent.

3) $.04 \times 42 \times .053 \times 100 = 8.9$ cents per barrel crude oil.

For "A" plants the joint cost reflects an exchange arrangement with a large refinery. This cost is 21 cents per barrel crude oil processed.

The annual costs for controlling all other airborne emissions are presented in Exhibit C-6 and converted to cents per barrel crude oil processed. At the bottom of Exhibit C-6 an alternate "C" category is considered which has conversion facilities other than catalytic cracking (hydrocracking and/or coking). Catalytic cracking emission control costs are not needed for alternate "C" types.

Unit costs are presented as a function of volume of crude oil processed for "C" and "R" plants in Exhibit C-7 and for "T" and "A" plants in Exhibit C-8. These Exhibits are used to estimate the cost of airborne emission controls for each individual refinery for which water flow data was available.

3. Lead Removal Costs

Table V-2 in Part Two provides lead removal costs for a typical 7.5 thousand barrels per day refinery (M-1 Model). This model contained both catalytic cracking and reforming. Since the clear research octane number of (butanized) catalytic cracked gasoline is essentially equivalent to that required for unleaded gasoline, it was assumed that all the cost increases were involved in increasing the octane number of straight-run stocks1). Therefore, the same costs on a per-barrel-crude basis can be applied to both "R"-type and "C"-type plants.

Accordingly, lead removal costs were developed for prototypes "R" and "C" using an 0.6 scale factor for capital charges and a 1.0 scale factor for all other costs. Results of these calculations are summarized below:

---

1) Since these refineries process high gravity crude oils which contain a high percentage of straight-run naphtha, motor octane number is not usually a problem.

COSTS OF AIRBORNE EMISSION CONTROL IN PROTOTYPE REFINERIES

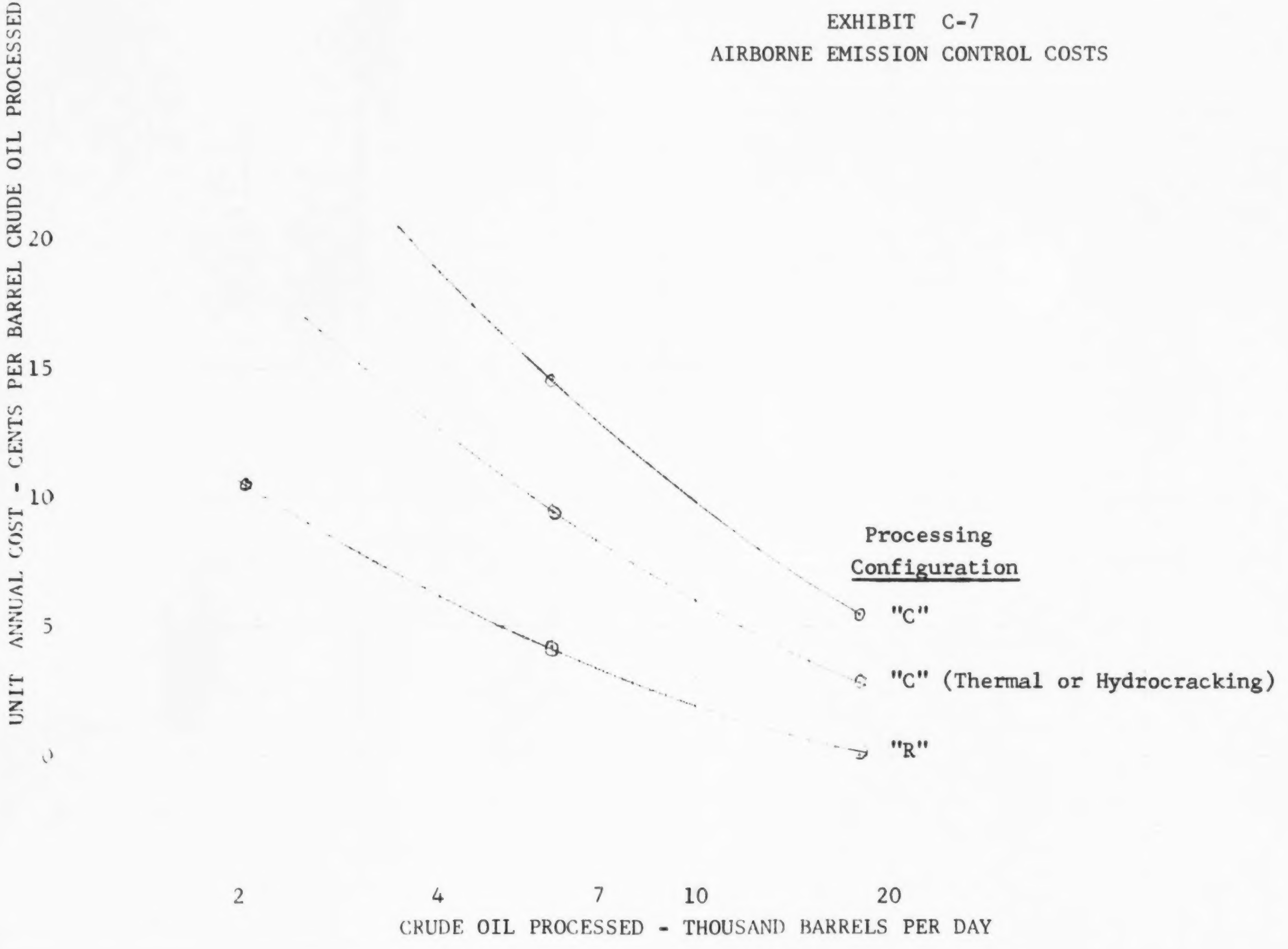
(Excludes refinery liquid fuel sulfur reduction)

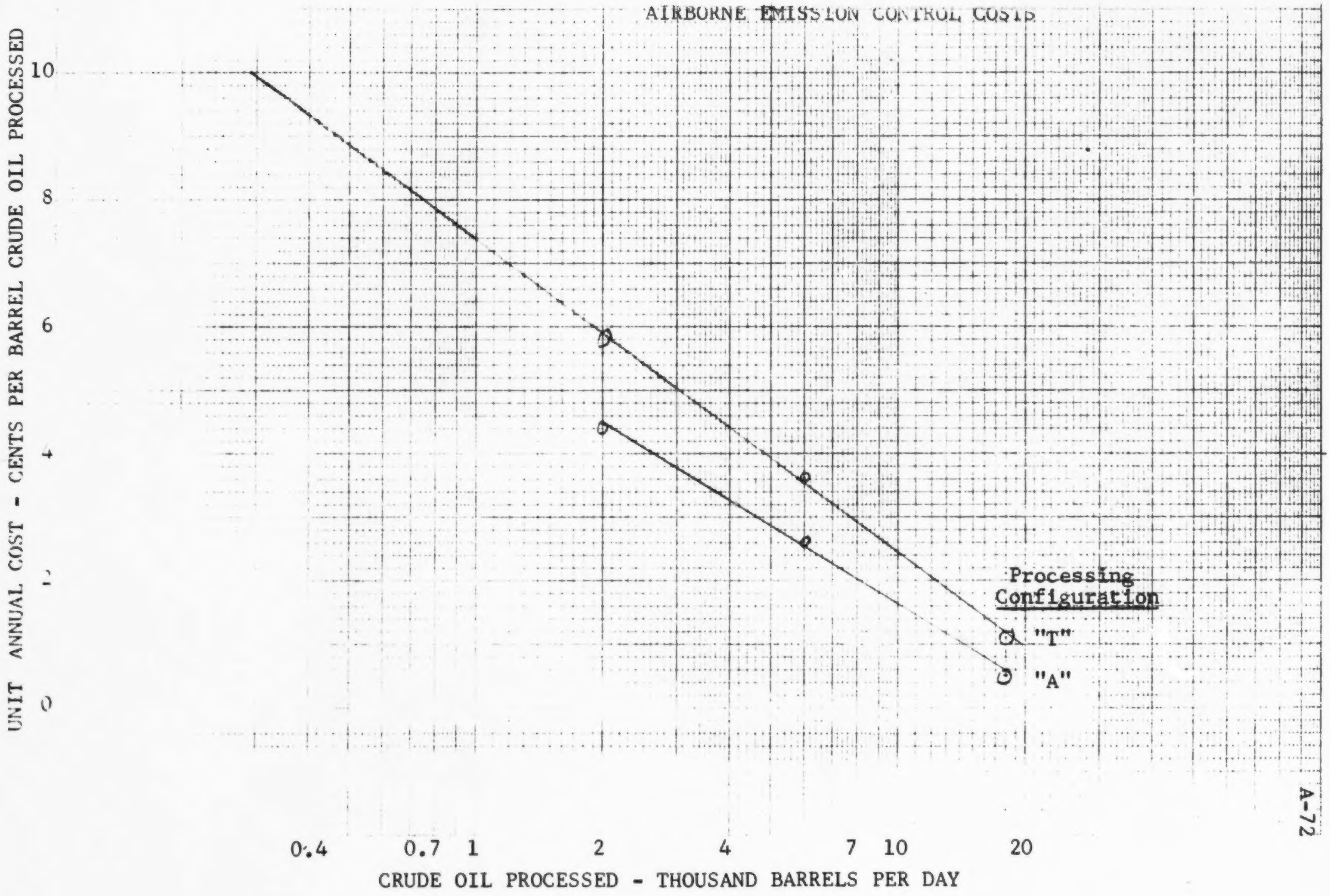
Prototype Crude Oil Processing Capacity & Identification	2T	2A	2R	6T	6A	6R	6C	13T	18A	18R	18C
Costs-Thousand Dollars Per Year											
Tankage											
Crude Oil	20	20	20	32	32	32	32	5	5	5	5
Gasoline	-	-	24	-	-	30	55	-	-	-	-
Jet Fuel	20	10	-	44	22	-	-	65	26	-	-
Loading Rack	-	-	33	-	-	27	16	-	-	-	-
API Separator	2	2	2	3	3	3	3	4	4	4	4
CO Boiler	-	-	-	-	-	-	16	-	-	-	-
Catalytic Cracking Precipitator	-	-	-	-	-	-	99	-	-	-	176
Amine	-	-	-	-	-	-	22	-	-	-	45
Claus	-	-	-	-	-	-	16	-	-	-	29
Tail Gas	-	-	-	-	-	-	62	-	-	-	103
Total	42	32	79	79	57	92	321	74	35	9	362
Crude Oil Processed-Thousand Barrels Per Year	--- 730 ---			--- 2,190 ---				--- 6,570 ---			
Crude Oil-Cents Per Barrel	5.8	4.4	10.8	3.6	2.6	4.2	14.6	1.1	.5	.1	5.5

Alternate "C" (excludes CO Boiler and Catalytic Cracker Precipitator)

	6C	18C
Thousand Dollars Per Year	206	186
Cents Per Barrel-Crude Oil	9.4	2.9

EXHIBIT C-7
AIRBORNE EMISSION CONTROL COSTS





AIRBORNE EMISSION CONTROL COSTS

	Refinery Size Thousand Barrels Per Day			
Cost - Dollars Per Day	7.5	2.0	6.0	18.0
Capital	1,530	690	1,340	2,590
All Other	770	210	620	1,850
Total	2,300	900	1,960	4,440
Cost - Cents Per Barrel				
Crude Oil	31	45	33	25

These results are plotted in Exhibit C-9 which was used to estimate lead removal costs for each specific refinery considered. For those six "C"-type plants which contain thermal cracking/coking rather than catalytic cracking, lead removal costs were increased by 25 percent (estimated without research) to account for the poorer octane quality of thermal gasolines.

4. Revenue Adjustments

In Chapter II, Section C, we estimated price changes that would occur for each product as a result of EPA's regulations. With one exception these price changes will be directly used to compute small refinery revenue adjustments. The exception is the residual fuel oil price premium. EPA price changes were derived from the EPA version of the model expansion. This version premised an 0.5 percent sulfur content residual fuel product. Existing refineries will only have to supply an 0.9 percent sulfur product. So their fuel oil price will be about 40 cents per barrel less than that received by the model expansion 1).

The revenue adjustments can now be computed:

---

1) 100 cents per barrel per one percent sulfur reduction - Part Two, page V-13.

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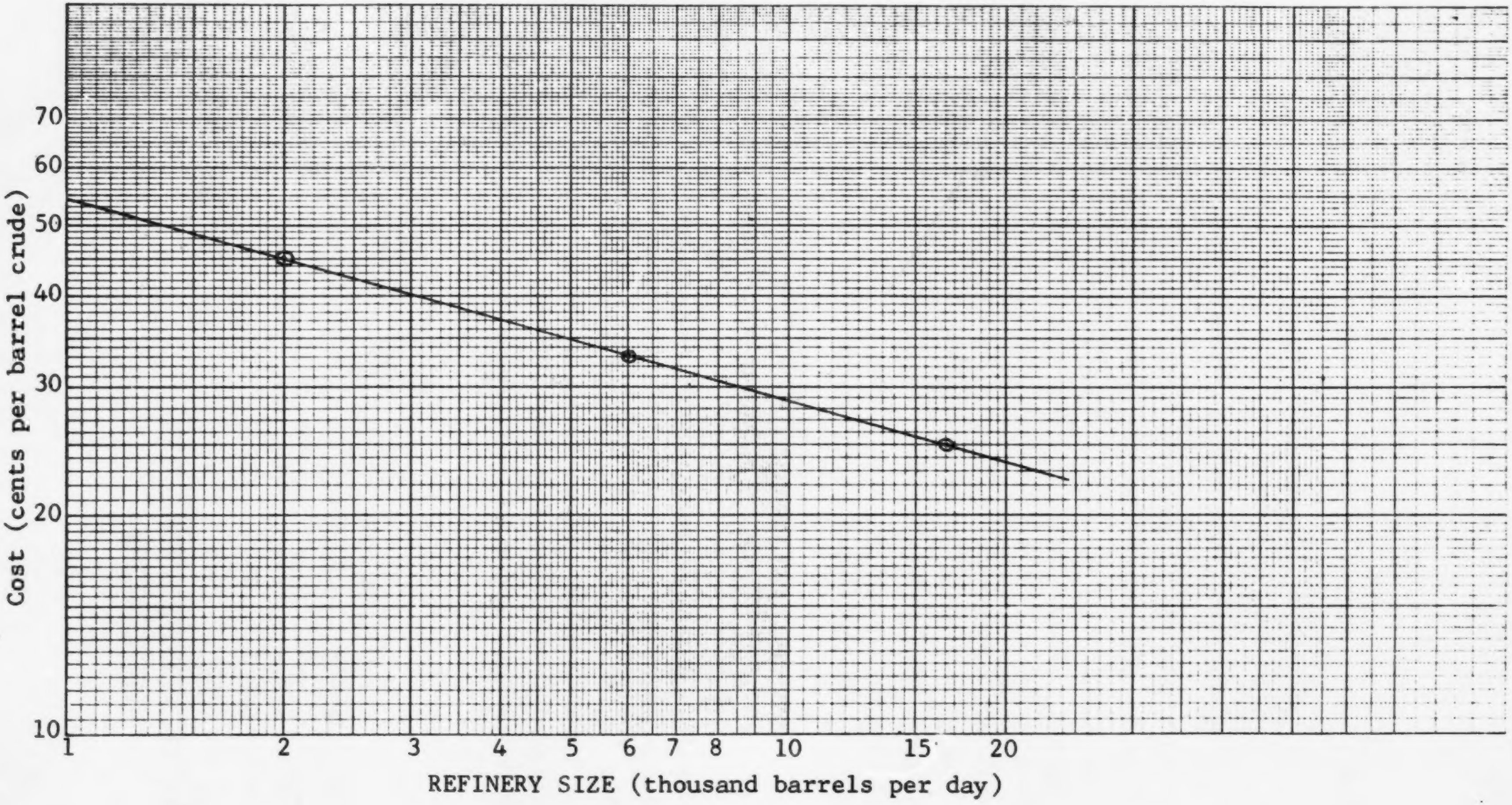
EXHIBIT C-9
LEAD REMOVAL COSTS



Product	EPA Price Increase Cents Per Barrel	Product Yields Percent of Crude Oil Processing Configuration "T"	"A"	"R"	"C"
Gasoline	42	-	-	35	63
Naphtha Jet Fuel	42	44	21	-	-
Distillate Fuel Oil	46	16	-	22	19
High Sulfur Distillate	6	-	24	-	-
Residual Fuel Oil	6	37	-	37	12
Asphalt	42	-	50	-	-
Total Revenue Adjustment - Cents Per Barrel Crude Oil Processed		28	32	27	36